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THE AMERICAN ENERGY INITIATIVE, PART 5: RECENT E.P.A. RULEMAKINGS RELATING TO BOILERS, CEMENT MANUFACTURING PLANTS, AND UTILITIES

HEARING

BEFORE THE

SUBCOMMITTEE ON ENERGY AND POWER

OF THE

COMMITTEE ON ENERGY AND COMMERCE

HOUSE OF REPRESENTATIVES

ONE HUNDRED TWELFTH CONGRESS

FIRST SESSION

APRIL 15, 2011

Serial No. 112–41

Printed for the use of the Committee on Energy and Commerce

energycommerce.house.gov

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U.S. GOVERNMENT PRINTING OFFICE
74–217 PDF WASHINGTON : 2012

For sale by the Superintendent of Documents, U.S. Government Printing Office
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THE AMERICAN ENERGY INITIATIVE, PART 5: RECENT E.P.A. RULEMAKINGS RELATING TO BOILERS, CEMENT MANUFACTURING PLANTS, AND UTILITIES

FRIDAY, APRIL 15, 2011

House of Representatives,
Subcommittee on Energy and Power,
Committee on Energy and Commerce,
Washington, DC.

The subcommittee met, pursuant to call, at 9:03 a.m., in room 2123 of the Rayburn House Office Building, Hon. Ed Whitfield (chairman of the subcommittee) presiding.

Members present: Representatives Whitfield, Shimkus, Walden, Burgess, Scalise, McMorris Rodgers, McKinley, Gardner, Pompeo, Griffith, Barton, Upton (ex officio), Rush, Inslee, Dingell, Markey, Green, Capps, Gonzalez, and Waxman (ex officio).

Staff present: Maryam Brown, Chief Counsel, Energy and Power; Allison Busbee, Legislative Clerk; Cory Hicks, Policy Coordinator, Energy and Power; Heidi King, Chief Economist; Mary Neumayr, Counsel, Oversight/Energy; Greg Dotson, Democratic Energy and Environment Staff Director; Caitlin Haberman, Democratic Policy Analyst; and Alexandra Teitz, Democratic Senior Counsel for Energy and Environment.

Mr. Whitfield. We will call the hearing to order this morning, and I look forward to the testimony of our panel. Before we get started, I want to just make a couple of comments relating to administrative issues. We had invited EPA representatives to testify at our hearing on Wednesday as well as today, and they were unable to attend. As a result of that, we are going to have another hearing and we are going to invite representatives of the agency to come. We know that there is more than one or two people that can testify over there, and I think that on this issue that we are looking at today, as well as others, it is imperative that we have testimony from EPA. So my staff is going to work with minority staff to schedule a time for Administrator Jackson or her designee to come before us in May after the Easter recess for a hearing with them.

So this is another hearing on our—and now I am going to recognize myself for a 5-minute opening statement.

OPENING STATEMENT OF HON. ED WHITFIELD, A REPRESENTATIVE IN CONGRESS FROM THE COMMONWEALTH OF KENTUCKY

This is another hearing on the American Energy Initiative in which we look at the impact of EPA regulations on providing fuel for our transportation needs and generating electricity for our other needs.

In an interview with the San Francisco Chronicle back in January of 2008, then-Presidential candidate Barack Obama, when asked a question, said that his administration was going to have the most aggressive cap and trade system that was out there. Then he said so if somebody wants to build a coal power plant, they can. It is just that our policies will bankrupt them because they are going to be charged a huge sum for all that greenhouse gas that is being emitted. That will generate billions of dollars that we can invest in solar, wind, and other alternative energies. Well, he was not successful in adopting a cap and trade system, but it is quite clear that EPA is taking up the mantle, and they are determined to pass regulations to increase the cost of coal and make other energy sources more competitive.

Today we are going to focus on only three of the multitude of regulations in the queue at EPA in which they are moving with unprecedented speed, and all of these are under Section 111 and 112 of the Clean Air Act. First, we have the utility rule, which affects the HAP standards for new and existing coal- and oil-fired electric generating units and new-source performance standards for fossil fuel-fired EGUs.

Second, we have the cement rule, which affects HAP standards and new-source performance standards for the Portland Cement manufacturing industry.

Third, we have HAP standards for large and small boilers. We also have a rule establishing new standards of performance and environment and emission guidelines for commercial and industrial incinerators.

And a fourth rule regarding secondary materials that are solid wastes.

I might also mention that every one of these rules is the result of a court settlement or a consent decree. It is becoming quite clear that lawsuits are the method now being used to regulate at EPA. In fact, just under the Clean Air Act, there are 509 lawsuits pending at EPA.

So we see this pattern of third-party groups filing lawsuits, EPA entering consent decrees, federal judges issuing—giving legal fees to the parties that brought the lawsuits in the first place. So if there was ever an act that is promoting lawsuits, it is this act.

Now we know from these regulations that plants are going to close. We know jobs are going to be lost. We know wholesale electric rates are going to go up. We know America is going to be less competitive in the global marketplace. And we know that there are some witnesses today who are going to speak in favor of these regulations. And there are those who say these regulations are good for America because it is going to create new industries and create new jobs. And as one of our witnesses said, that may be true sometime in the future, but we know with certainty it will eliminate real jobs today and inflate wholesale power rates today, not in the future. And then we need to be concerned about our capacity, we need to be concerned about reserve margins, we need to be concerned about the cost. These regulations alone, under EPA's conservative estimates, will cost industry over $14 billion a year.

So these are significant rules that have a dramatic impact on America as we try to revive our economy. And so I look forward to the testimony. I know that we need to have people supporting these rules, and we need to have people opposing these rules, because we need a national debate on the direction that EPA is going and the method that they are using to get there. To try to have a 60-day comment period on a 1,000-page rule with 1,000 additional technical pages is unacceptable.

[The prepared statement of Mr. Whitfield follows:]

STATEMENT OF THE HONORABLE ED WHITFIELD
CHAIRMAN, SUBCOMMITTEE ON ENERGY AND POWER
American Energy Initiative
Day 5 (MACT Regulations)

I would like to call this hearing to order. This is the fifth of our multi-day hearings on the American Energy Initiative. The American Energy Initiative is our comprehensive effort to address the nation's many energy challenges. Two days ago we addressed one of those challenges, rising gasoline prices. We focused on the Environmental Protection Agency's impediments to producing more domestic oil, especially in the waters surrounding Alaska. Today, we focus **not** on EPA regulations that restrict the supply of energy, but on regulations that make it **more** expensive to make energy and make it **more** expensive to make cement.

As everyone knows, EPA is issuing rules on Maximum Achievable Control Technology or MACT requirements for boilers, electric generating utilities, and cement facilities. Whether we are talking about the boilers used to produce steam for electricity at coal-fired power plants, or the boilers or process heaters found in virtually every manufacturing facility, they are the power source of a robust economy.

Thousands of power plants and facilities depend on affordable energy from boilers. That includes paper mills, refineries, and chemical plants, schools and hospitals. Literally millions of jobs rely on affordable energy from these facilities, and those jobs are put at risk if those boilers can no longer be installed and run in a cost effective manner.

And where manufacturing is concerned, we live in a global economy and need to be mindful that regulations that disproportionately raise the cost of building and operating boilers in the U.S. may chase manufacturing activity and jobs overseas. And as is so often the case with EPA regulations, few if any other nations have any desire to go down the same costly path as with these new boiler regulations.

That is why EPA's extremely stringent regulations are worrisome, especially given the state of the economy. And that is why easing compliance is so crucial to the economic recovery.

It is also important to recognize another aspect of these rules – they are but one of a multitude of major regulations with overlapping deadlines that have been placed in the pipeline by this Obama administration. Another of our American Energy Initiative proposals deals with this cumulative impact, and our discussion about boilers today is important in itself but also relevant to our discussion draft of the "Transparency in Regulatory Analysis of Impacts on the Nation Act" or TRAIN Act, which seeks to gather information on this cumulative burden of which these rules are a part.

I would like to close with one final concern of particular importance to me, and that is the Obama administration's war on coal. We have seen an assault on coal mining itself, including the revocation of a permit for a mine that had already been approved, and the creation of new water quality standards for mines that may be impossible to meet. This war on coal is a war on the economy in many states. But blocking coal mining is only part of the anti-coal agenda. These rules, which most heavily impact coal-fired utilities and coal-fired boilers, discourage the use of coal in the U.S. and is another aspect of the war on coal.

So as we learn from regulated entities and others what these regulations entail, let us not forget the larger context as well as we seek ways to implement regulations in concert with a robust economy.

I would like at this point to provide a scheduling note for the benefit of my colleagues. Unfortunately, no one from EPA was able to testify at either Wednesday's hearing or today's hearing. We did, of course, invite the Agency to come, and we look forward to their testimony on a future day of the American Energy Initiative hearing. So I have directed my staff to work with the minority staff to schedule a time for Administrator Jackson or her designee to come before us in May, after our Easter recess.

With that, I now recognize Mr. Rush for five minutes for his opening statement.

Mr. WHITFIELD. So at this time I recognize the gentleman from Illinois for his 5-minute opening statement.

OPENING STATEMENT OF HON. BOBBY L. RUSH, A REPRESENTATIVE IN CONGRESS FROM THE STATE OF ILLINOIS

Mr. RUSH. I want to thank you, Mr. Chairman, for having this hearing, and I want to thank all of the guests for attending today's hearing.

Mr. Chairman, I must say that your argument sounds persuading, but some of it is not persuading that the EPA is the real culprit here. Today, Mr. Chairman, we will hear testimony from a variety of stakeholders on proposed or finalized EPA rules regarding the maximum achievable control technology, or MACT, and other standards for power plants, cement facilities, boilers, and incinerators. Mr. Chairman, Section 112 of the Clean Air Act mandates that EPA establish technology-based standards to reduce hazardous air pollutants, HAPs, that may contribute to increased cases of cancer, birth defects, and other harmful defects, and adverse environmental impacts.

We will all understand that EPA is required by law under the Clean Air Act to issue each of these rules on a specified schedule, and all of these schedules were actually mandated to be completed by the year 2000. Initially we all know that facilities will have an additional 3 and in some cases even up to 4 years to comply with these rules, plus we are finalizing in State or federal authorities determines that additional time is necessary to install pollution control.

Now Mr. Chairman, I am not a math major, but it would seem to me that if these rules were supposedly issued way back in 2000 and we are now in the year 2011 and facilities will still have up to 3 to 4 years to install these controls once they are finalized, then plant operators will have at least 15 years of delay in meeting these standards, even if all these rules were finalized today.

Today, Mr. Chairman, we will be hearing contrasting testimony by interested stakeholders on how compliance with these rules will impact energy rates and reliability, jobs and the economy as well. This is the time for us to consider the impact of these rules on rates and reliability on jobs.

First is those utility companies that have been proactive in preparing for these rules and some of these utility companies have been proactive in preparing for these rules, which everyone understood to—that they were coming. These prepared utility companies will testify on how these rules are balanced and they are reasonable. That EPA has engaged the industry in a transparent manner, and they have no problem meeting these standards because they have already invested in these controlled technologies.

These forward-thinking companies which must be commended and applauded and lifted up will also testify that implementing these pollution control technologies can indeed advance economic growth, inspire innovation and competitiveness, and actually create well-paying jobs through the installation of scrubbers, air quality control systems, and other pollution control equipment.

In addition to these economic benefits, we will also hear about some of the health and environmental benefits that compliance with these rules would bring. Specifically, just a reduction in mercury and particulate matter alone will lead to significant and tangible health benefits, including the prevention of thousands of premature deaths, non-fatal heart attacks, chronic bronchitis, and associated asthma cases.

Unfortunately, we will also hear the other side of the story as well. Naturally, these companies who have been less active in planning and investing in pollution control technologies over the years will testify that they are, as a result, unprepared for compliance and will request additional time to do so. In essence, they are going to be whining at the table. Since there is no legislation up for a debate now today, I will reserve judgment on the merits of pushing these rules down the road for future action once again, and I look forward to today's testimony and the subsequent questions of our witnesses.

Mr. Chairman, with that I yield back the balance of my time.

Mr. WHITFIELD. Thank you. At this time I recognize the chairman of the Energy and Commerce Committee, Mr. Upton of Michigan, for 5 minutes.

Mr. UPTON. Well thank you, Mr. Chairman. I too regret that EPA was not able to be with us this morning.

OPENING STATEMENT OF HON. FRED UPTON, A REPRESENTATIVE IN CONGRESS FROM THE STATE OF MICHIGAN

The American Energy Initiative is an ambitious effort to take on all of the energy-related issues that the Nation faces today and into the future. With high and rising gas prices, Middle East instability, and a domestic economy struggling to regain its footing and create jobs, the current energy challenges certainly are great, and with global industrial competition and related worldwide energy demand going nowhere but up, we need to take these issues on now before they get out of hand.

What is most disturbing is how many of these energy challenges are self-imposed. Two days ago this subcommittee heard from Alaska's entire congressional delegation—many of them—as well as local officials—all of them—and energy company representatives from the State. Alaska is practically begging to produce more of its substantial reserves of domestic oil and help bring down future gasoline prices. The fact that EPA continues to stand in the way is both inexplicable and unacceptable. America has plenty of outside enemies who would love to cut off our energy supplies. We don't need to make things worse by being our own enemy as well.

Every bit as bad are EPA regs that raise electricity costs and stifle our manufacturing competitiveness. Our fifth day of the hearing on the American Energy Initiative deals with a set of regulations, those impacting utility steam generating units, boilers, and cement. Raising the cost of operating utility steam generating units means higher electricity prices for everybody. Since boilers and process heaters are used at nearly every manufacturing facility, they also certainly raise manufacturing costs. Few, if any, of the other countries, including our industrial competitors, are pursuing similar policies to raise costs. Needless to say, there is not much of an export market for EPA's ideas and how to run this part of our economy.

With unemployment long stuck above 8 percent, higher in manufacturing areas like mine, we need to be mindful of regs that make energy more expensive and discourage investment in the domestic manufacturing sector. Beyond power plants and manufacturers, other facilities with boilers, such as universities, will face higher operating costs at a time when State governments are hard-pressed to increase funding levels in tuition bills that are already way too high for most students to pay.

The goal is not to repeal these regs; it is to advance them in a reasonable way. Regs that reduce emissions without reducing manufacturing activity and jobs or creating other undue hardships.

I look forward to the discussion and plan to incorporate what is learned into the American Energy Initiative.

I yield to Mr. Barton.

[The prepared statement of Mr. Upton follows:]

Statement of the Honorable Fred Upton
Chairman, Committee on Energy & Commerce

April 15, 2011
Subcommittee on Energy and Power
Hearing on "The American Energy Initiative – Focus on Recent EPA Rulemakings Relating to Boilers, Cement Manufacturing Plants, and Utilities"

The American Energy Initiative is an ambitious effort to take on all of the energy-related issues the nation faces today and into the future. With high and rising gasoline prices, Middle East instability, and a domestic economy struggling to regain its footing and create jobs, the current energy challenges are great. And with global industrial competition and related worldwide energy demand going nowhere but up, we need to take these issues on now before they get out of hand.

What is most disturbing to me is how many of these energy challenges are self-imposed. Two days ago, this subcommittee heard from Alaska's entire congressional delegation as well as local officials and energy company representatives from the state. Alaska is practically begging to produce more of its substantial reserves of domestic oil and help bring down future gasoline prices. The fact that EPA continues to stand in the way is both inexplicable and unacceptable. America has plenty of outside enemies who would love to cut off our energy supplies; we don't need to make things worse by being our own enemy as well.

Every bit as bad are EPA regulations that raise electricity costs and stifle our manufacturing competitiveness. Our fifth day of the hearing on the American Energy Initiative deals with a set of regulations – those impacting utility steam generating units, boilers and cement.

Raising the cost of operating utility steam generating units means higher electricity costs for everyone. And since boilers and process heaters are used at nearly every manufacturing facility, they also raise manufacturing costs. Few if any other countries, including our industrial competitors, are pursuing similar policies to raise costs. Needless to say, there is not much of an export market for EPA's ideas on how to run an economy.

With unemployment long stuck above 8 percent – and higher in manufacturing states like mine – we need to be mindful of regulations that make energy more expensive and discourage investment in the domestic manufacturing sector.

Beyond power plants and manufacturers, other facilities with boilers such as universities will face higher operating costs at a time when state governments are hard pressed to increase funding levels and tuition bills are already tough for many students to pay.

The goal is not to repeal these regulations. It is to advance them in a reasonable way – regulations that reduce emissions without reducing manufacturing activity and jobs or creating other undue hardships.

I look forward to this discussion and plan to incorporate what is learned into the American Energy Initiative. Thank you.

Mr. BARTON. Thank you, Mr. Chairman—both Mr. Chairmans. Thank you for holding this hearing.

OPENING STATEMENT OF HON. JOE BARTON, A REPRESENTATIVE IN CONGRESS FROM THE STATE OF TEXAS

We have a very difficult economy. We all know that. The Environmental Protection Agency, I think this is our third or fourth hearing this week in which they have been invited to attend and I think they have come to one. We could call them the Evaporating Personnel Administration, I guess. They don't seem to ever show up and be accountable.

Mr. RUSH. Will the gentleman yield?

Mr. BARTON. I will, on your time. I am always happy to yield on your time.

They have consistently—they being the EPA—made problematic decisions with their proposed regulations, rulings, and in some cases, pulling the existing permits as they have done in Texas without cause. These threaten our Nation's energy security at a minimum and our economic opportunity for sure.

The regulations that EPA is proposing as the subject of this hearing will decrease reliability in our energy sector, increase the cost of our energy, and kill jobs. The latest and greatest scheme to regulate the hazardous air pollutants from power plants under the Clean Air Act Section 112 will amend the new source performance standards with regard to the new utility maximum achievable control technology, or MACT. Some people call it big MACT standards. This would cause an adverse effect on coal and oil electric generating plants throughout our country.

The EPA seems to be going after a number of different industries, but it is apparent to me that they are actually attacking the most prevalent economical resource generation in the United States, and that is the coal industry.

The timeline that EPA is proposing is unworkable, unreasonable, and uneconomical. Their statistical data are skewed. They base their proposal on the average of the 12 best—12 percent best performing plants in the country. The results do not reflect the real life activity of existing power plants across the Nation. With so many compliance factors involved, no one plant can possibly expect to comply with all of the MACT limits on all modes of operation.

To comply with the EPA's utility MACT proposal, it will cost $11 billion annually across the electric generation industry. Cement is an additional $1 billion. Under the boiler rules, $2.3 billion is indicated by the EPA in cost to the refinery industry. If you add that up, that is almost $14 billion, Mr. Chairman.

And finally, last but not least, I do find it troubling that Lisa Jackson, once again, is a no-show at a very important hearing that she has had every opportunity to be in attendance. The MACT truck is about to overrun us all, and she is not even here to comment on the proposed regulations.

With that I yield back, Mr. Chairman.

[The prepared statement of Mr. Barton follows:]

Opening Statement of the Honorable Joe Barton
Chairman Emeritus, Committee on Energy and Commerce
Subcommittee on Energy & Power Hearing
"The American Energy Initiative V"
EPA Rulemakings on Utilities, Cement Manufacturing Plants, and Boilers

April 15, 2011

Thank you Mr. Chairman for conducting this important hearing today. Let's talk some basic facts. This is the worst economy in generations. The Environmental Protection Agency (EPA) continues to undermine the authority of Congress and individual States to oversee and make considerations. They have consistently made problematic decisions within their proposed regulations, rulings, and pulling permits without cause, that threaten our Nations Energy Security. The regulations the EPA is proposing will decrease reliability from plant closures, increase energy costs' and kill jobs.

The latest and greatest scheme to regulate hazardous air pollutants (HAPS) from power plants under the Clean Air Act Section 112 will amend the New Source Performance Standards (NSPS) with regards to their new Utility Maximum Achievable Control Technology standards (MACT). This would cause an adverse effect on coal and oil electric generating units (EGU's).

The EPA is going after many different industries, but it is outright attacking the most prevalent economical resource in the United States for their own political agenda.

The timeline the EPA is proposing is unworkable, unreasonable and uneconomic. Their statistical data is skewed by basing their figures on the average of the best performing twelve percent of the plants for which the EPA has emission data. So the results do not reflect real life data activity of existing power plants across the nation. With so many compliance factors presented by the EPA, no one plant could possibly be expected to comply with the MACT limits on all modes of operation.

To comply with EPA's Utility MACT proposal, it will cost almost 11 billion dollars annually across the electric power industry. Cement ruling will be 950 million dollars annually for cement manufacturers. Under the boiler rules, 2.3billion dollars annually is indicated by the EPA, in costs, to the refineries manufacturers, paper mills and chemical companies.

I find it troubling that the EPA declined the opportunity to defend this heavy-handed proposal today. Lisa Jackson is trying to run over our Country with her EPA 'MACT' truck, hobbling our economy.

Mr. WHITFIELD. Thank you very much. Mr. Waxman is on his way. He has been delayed, so he will have a 5-minute opening statement when he gets here, but in the meantime, I want to introduce our panel. We do appreciate all of you coming to help us examine in a more thorough way the implications of these regulations.

We have Mr. Tom Fanning, Chairman, President, and CEO of Southern Company. We have Mr. Anthony Earley, Executive Chairman, DTE Energy. We have Mr. Michael Bradley, Executive Director of The Clean Energy Group. We have Mr. Paul Kempf, Director of Utilities at Notre Dame University—University of Notre Dame. We have Mr. John Walke, who is the senior Attorney and Clean Air Director for the Natural Resources Defense Council. We have Mr. Dirk Krouskop, Vice President, Safety, Health & Environment at MeadWestvaco Corporation, and we have Mr. Aris Papadopoulos, President and CEO of Titan America.

We thank all of your for being here. We have one vote on the House Floor right now. We like to start these hearings early so we don't have to be interfered by votes, so we have one Member going over to vote. He is going to come back, but in the meantime, we will go on and get these opening statements going because we want to get them on the record.

So Mr. Fanning, I will recognize you for 5 minutes for your opening statement.

STATEMENTS OF TOM FANNING, CHAIRMAN, PRESIDENT AND CHIEF EXECUTIVE OFFICER, SOUTHERN COMPANY; ANTHONY F. EARLEY, JR., EXECUTIVE CHAIRMAN, DTE ENERGY; MICHAEL J. BRADLEY, EXECUTIVE DIRECTOR, THE CLEAN ENERGY GROUP; PAUL KEMPF, DIRECTOR OF UTILITIES, UNIVERSITY OF NOTRE DAME; JOHN WALKE, SENIOR ATTORNEY AND CLEAN AIR DIRECTOR, NATURAL RESOURCES DEFENSE COUNCIL; DIRK KROUSKOP, VP, SAFETY, HEALTH & ENVIRONMENT, MEADWESTVACO CORPORATION; AND ARIS PAPADOPOULOS, PRESIDENT AND CEO, TITAN AMERICA LLC.

STATEMENT OF TOM FANNING

Mr. FANNING. Thank you. Chairman Whitfield, Ranking Member Rush, and members of the subcommittee, thank you for inviting me to testify today.

Southern Company is the leading energy supplier in the Southeastern United States, and one of the largest generators of electricity in the Nation. We work hard every day to ensure that our customers have access to reliable and affordable power. Like the rest of our industry, we are committed to working with our communities, stakeholders, and our customers to continue reducing our environmental impact. That is why Southern Company in recent years has invested over $8 billion in environmental controls, and intends to spend up to $4.1 billion to comply with existing, revised, or new rules over the next 3 years.

We are glad that you are examining and discussing the utility MACT rule that EPA recently proposed. We are very concerned with this proposal and believe that if adopted, it could put the reliability and affordability of our electric supply at risk. The rule would impact plants responsible for nearly 50 percent of total electricity generation. It would impose an unrealistic 3-year timeline for compliance at a time when the industry is laboring to comply with numerous other mandates. The result could be the reduced generating capacity below the minimum required to provide reliable service and also cause electric rates to substantially increase.

However, we believe these risks can be reduced or avoided by moving forward on a reasonable schedule that reflects industry experience and the challenges of upgrading the Nation's generating fleet.

I have four points for your today.

The first is that the timeline for this rule is unreasonable. The Agency has proposed to allow only 60 days to comment on one of the most burdensome and expensive rules that was ever put forward. We looked at nine other less complex rules, and found that EPA has allowed between 120 and 180 days for comments on each of them. This is nearly a 1,000-page rule with nearly 1,000 more pages of technical supporting documents. Sixty days is plainly inadequate for the industry to analyze this rule and its effects, and to offer meaningful comments.

But even a greater concern is the 3-year compliance period that would follow this particular MACT rule. A study conducted for the Electric—Edison Electric Institute by ICF concluded that for U.S. by 2015, over 80,000 megawatts of scrubbers and over 160,000 megawatts of fabric filter baghouses will be required to be constructed. Almost 80,000 megawatts of current coal capacity will retire and have to be replaced. As the CEO of a company that has installed more pollution controls than any other utility, I tell you that this cannot be done in 3 years.

That leads to my second point, which is that this rushed timeline could put the reliability of the Nation's electric generating system at risk. The major challenge of complying with these new rules is ensuring adequate reserve margins, that is, the generating capacity that is available during times of high demand or during interruptions in service from base load plants. According to Bernstein Research, the impact of utility MACT rule on smaller plants will cause regional capacity margins to plummet by 7 to 15 percentage points into the single digits in some regions. Other studies have reached similar conclusions. The result will be a greater risk of power outages.

My third point is that the rushed timeline will also impact electricity affordability. The construction of the massive numbers of controls that I mentioned, plus the costs of replacing the coal plants that will retire will require utilities to spend as much as $300 billion by 2015. This huge cost will certainly show up in customers' power bills and will threaten jobs and any economic recovery.

My fourth and final point is that there is a better way to continue to improve our environmental performance while protecting our customers, reliability, and jobs. We need a realistic compliance schedule based on historical experience that allows us to retrofit existing plants and to begin work on any replacement capacity. A realistic schedule would allow upgrades to be made in an orderly fashion without placing reliability in jeopardy or imposing undue additional cost increases on our customers.

To conclude, we believe that the utility MACT proposal on its current schedule and in its current form puts at risk the reliability and affordability of power in the United States. These risks can be reduced by extending the rulemaking schedule and the timeline for compliance. During that time, we can work to improve and refine the proposed rule, and simultaneously better prepare for any changes in our generation fleet. This is a commonsense solution that all stakeholders should be able to support.

I thank the committee for holding this important hearing today and giving me the opportunity to testify. I look forward to any questions you might have.

[The prepared statement of Mr. Fanning follows:]

Recent EPA Rulemakings Relating to Boilers, Cement Manufacturing Plants, and Utilities

Thomas A. Fanning,

Chairman, President, and Chief Executive Officer,

The Southern Company

EPA has proposed Utility MACT rules under timelines that we believe will put the reliability and affordability of our nation's power system at risk. EPA's proposal will impact plants that are responsible for nearly 50 percent of total electricity generation in the United States. It imposes a three-year timeline for compliance, at a time when the industry is laboring to comply with a myriad of other EPA mandates. The result will be to reduce reserve margins—generating capacity that is available during times of high demand or plant outages—and to cause costs to soar. Lower reserve margins place customers at a risk for experiencing significant interruptions in electric service, and costs increases will ultimately be reflected in service rates, which will rise rapidly as utilities press ahead with retrofitting and projects to replace lost generating capacity due to plant retirements.

The solution is to allow the industry the time to make a smooth transition to the next generation of emissions control technology required by the Utility MACT standard. A more deliberate schedule for promulgating the standard, coupled with a more realistic compliance schedule, would ease the strain on the industry and reduce risks to consumers. Anything less will put at risk the economic growth and job creation that depends on reliable and affordable electricity every day of the year.

Congressional Testimony

Recent EPA Rulemakings Relating to Boilers, Cement Manufacturing Plants, and Utilities

Thomas A. Fanning,
Chairman, President, and Chief Executive Officer,
The Southern Company

Testimony before the
Subcommittee on Energy and Power
Committee on Energy and Commerce,
United States House of Representatives

April 15, 2011

Chairman Whitfield, Ranking Member Rush, and Members of the Subcommittee, thank you for inviting me to testify today. The Southern Company is the leading energy supplier in the Southeastern United States, serving 4.4 million customers with reliable electricity service generated from a full portfolio of energy resources—nuclear, Twenty-First Century coal, natural gas, renewables and energy efficiency. We work hard every day to ensure that our customers have access to reliable and affordable power. Like the rest of our industry, we are committed to working with our environmental regulators, reducing emissions and making sure the air is clean. That is why Southern has in recent years invested over $8 billion dollars in environmental controls and intends to spend up to $4.1 billion over the next three years to comply with existing, revised or new rules. The results have been impressive: between 1990 and 2010, Southern Company reduced SO_2 and NO_x emissions by about 70 percent, even as generation increased by about 40 percent. Moreover, by 2020, we expect reductions that will result in SO_2, NO_X and Hg emissions 60-80 percent below 2000 levels, while generation again is expected to increase by about 40 percent during this same period.

My message today is that the reliability and affordability that Americans deserve from their power system is at risk. EPA's proposal for a new maximum achievable control technology standard for the utility industry, or "Utility MACT," will impact plants responsible for nearly 50 percent of total electricity generation in the United States. It imposes a three-year timeline for compliance, at a time when the industry is laboring to comply with a myriad of other EPA mandates. The inevitable result will be to reduce reserve margins—generating capacity that is available during times of high demand or plant outages—and to cause costs to soar. Lower reserve margins place customers at a risk for experiencing significant interruptions in electric service, and costs increases will ultimately be reflected in service rates, which will rise rapidly as utilities press ahead with retrofitting and projects to replace lost generating capacity due to plant retirements.

The solution is to allow the industry the time to make a smooth transition to the next generation of emissions control technology required by the Utility MACT standard. A more deliberate schedule for promulgating the standard, coupled with a more realistic compliance schedule, would ease the strain on the industry and reduce risks to consumers. Anything less will put at risk the economic growth and job creation that depend on reliable and affordable electricity every day of the year.

Background on the Utility MACT Rule

On March 16, EPA Administrator Lisa Jackson signed the Agency's proposed rule to regulate hazardous air pollutants (HAPs) from power plants under Clean Air Act Section 112. The proposal would set stringent numerical emissions limits and work practice standards for a variety of HAPs emitted by coal and oil electric-generating units. The proposal also would amend the New Source

Performance Standards emission limits for particulate matter, sulfur dioxide, and nitrogen oxides for steam electric generating units.

MACT emission limits for existing units must be based on the average of the best performing twelve percent of the plants for which the EPA has emission data. For new units, the emission limits must be based on the best performing source. Since EPA chose to set limits separately by individual pollutants using different sets of best performing plants, EPA's resulting suite of emission limits does not reflect performance of any existing plant, but instead reflects the performance of a so-called "Frankenplant," one consisting of mixed-suite performance characteristics that do not represent the technology applications across all pollutants for any individual facility. As a result, it is unlikely that any single existing plant can meet all of the MACT limits on a continuous basis during all modes of operation without some addition of and/or optimization of existing control devices. And perversely, optimization of control device combinations for a single pollutant or set of pollutants could also have a detrimental effect on emissions of other pollutants controlled by the same technologies. This conflict potentially puts compliance with other standards in jeopardy.

While there have been many twists and turns over two decades, the most significant regulatory landscape shift leading to this proposed rule occurred in February 2008, when the D.C. Circuit vacated the final Clean Air Mercury Rule cap-and-trade program, which utilities were planning to implement through additional controls. Subsequently, at the beginning of 2010, EPA sent an extensive request for information to all utilities. The request required more than 450 units to conduct stack sampling to provide EPA emissions information on five groupings of HAPs: mercury, non-mercury trace metals, acid gases, organics and dioxins/furans. EPA never explained its legal rationale for requiring generating units to collect emissions information of all HAPs, despite its prior legal conclusion that it only had legal authority to set MACT limits for mercury emissions from coal-fired units. In March 2011 came the latest policy shift, the one that is the subject of this hearing. The Utility MACT proposed rule contains stringent emissions standards for a number of HAPs in addition to mercury. Even EPA estimates the rule, as proposed, will cost at least $10.9 billion annually, making it one of the most expensive rules in EPA's history.

A Wave of Overlapping Regulations

The Utility MACT proposed rule must be considered in the context of EPA's overall regulatory scheme. Over the past year, EPA has been developing a myriad of environmental regulations, many of which focus on the electric utility industry and specifically on coal-fired electric generators. These regulations include:

- The Transport Rule (CATR, replacement for the Clean Air Interstate Rule),
- Coal Combustion Residuals or By-products (CCRs) rules,

- National Ambient Air Quality Standards (NAAQS) for SO_2, NO_2, Ozone, and PM,
- Section 316(b) rules regarding plant cooling water intake structures,
- The climate change Endangerment Finding and the resultant triggering of -
- New Source Review on new and modified sources for greenhouse gases,
- Effluent guidelines for electric utilities, and
- Industrial Boiler MACT.

These regulations will have the most significant impact on roughly 400,000 MWs of oil-and coal-fired generation, which is about 40 percent of the current, available capacity in the U.S., and makes up nearly 50 percent of the U.S. total electricity generation. The aggregate impact of these regulations will require unprecedented levels of expenditures by utilities over a short period of time. Requiring utilities to overhaul their systems in three years raises two potential problems for consumers: reliability of service and affordability of electricity.

EPA's Promulgation and Compliance Timeline Is Unreasonable

1) Rushed Promulgation

The Utility MACT rulemaking process is currently driving the timing of decision making on control installation or replacement generation. Under the consent decree schedule that EPA agreed to, the rule must be finalized by November 2011. As a preliminary matter, EPA is not allowing enough time for public comment because of the short timeline to finalize the rule. Our technical team looked at nine other less complex environmental rules and found that EPA had ultimately allowed between 120 and 180 days for comment. Here, the schedule that EPA voluntarily agreed to under the consent decree is posing an undue restriction on the public comment period. Obviously, the rule has far-reaching implications to the electricity supply in the United States and yet EPA is only allowing sixty days for public comment. This is nearly a 1,000-page rule with nearly 1,000 more pages of technical supporting documents, some of which have yet to be posted. Sixty days for public comment on a rule of this magnitude is insufficient and is much less than has been allowed for previous MACT standards (e.g., Cement MACT, Industrial Boiler MACT, etc.). Our industry and the country need time to evaluate the proposed rule, but also time to understand the underlying data, assumptions and calculations that EPA used to derive the standards. These are critically important tasks that must be undertaken to determine if the proposed MACT standards reflect emission levels that were actually "achieved" and whether or not the standards are "achievable."

Likewise, EPA must take enough time to respond to the hundreds, if not thousands, of significant public comments it will receive on this rulemaking. EPA clearly rushed the proposed rule out the door to meet the consent decree. Our experts have already identified numerous factual and technical flaws in the proposed rule that must be corrected before the rule is finalized. EPA must allow enough time between the submission of comments and the issuance of the final rule to fully address these factual, technical and operational concerns. If EPA likewise rushes the final rule out the door without responding to the numerous issues addressed in comments, utilities will be forced to comply, if possible, with a rule that is technically and factually in error.

Most important, EPA has the ability to extend the rulemaking schedule. The court clearly indicated that EPA could seek additional time to finalize the rule if need be. In response to industry's concerns about the rulemaking schedule, the court noted that it "appreciates the industry's concern that this schedule may be too hasty for the critical and expensive regulatory decisions that will be made; however, the proposed Consent Decree allows for a change of schedule if need be." Further, the court noted that, "if the science and analysis require more time, EPA can obtain it." Given the stakes, why would EPA not take such a prudent step?

2) Inadequate Compliance Period

If EPA does not seek relief from the court-ordered deadline, the rule must be finalized by November 2011, becoming effective in early 2012. We would suggest that the Clean Air Act Section 112 MACT program has never had to deal with the scale of technology retrofits contemplated by EPA's proposed Utility MACT. While facilities in other MACT industrial categories have been required to install control devices in previous EPA rulemakings, these rulemakings did not require the installation of two or more large-scale control devices at potentially hundreds of facilities, each with an installation time measured in years, and costing hundreds of millions of dollars. Moreover, we have to remember that these facilities are part of an interconnected grid where work at one plant can affect energy supplies across an entire region. A three-year compliance timeline makes no sense when viewed through the lens of EPA's proposed Utility MACT. Because utilities are largely accountable to utility regulators, only when the rule becomes final can electric utilities determine the specific retrofits needed to assure compliance of all 400,000 MWs of oil- and coal-fired generation. Without judicial or congressional action, for the moment, compliance is mandated within three years of the Utility MACT rule's effective date, leaving utilities only from November 2011 to early 2015 to complete the following activities:

- Develop compliance strategies,
- Engineer technology and/or operational solutions on a unit-by-unit basis,
- Obtain required environmental permits for construction of control equipment,
- Gain state public utility commission (PUC) regulatory approval for cost of control equipment,
- Procure and install the required technology,
- Complete necessary transmission upgrades,
- Test the technology along with any operational changes, and
- Demonstrate full compliance.

Although the Utility MACT is the most definitive 2015 compliance deadline, the additional rulemakings mentioned above will have compliance deadlines before, on or soon after 2015. Costs associated with the additional rulemakings will have to be incurred over similar timeframes to ensure meeting those deadlines. Planning and installing compliance technologies to meet all of the applicable new environmental regulations is daunting.

Southern Company is concerned about the ability of the industry to build new environmental controls or replacement capacity in three years to comply with the Utility MACT rule. A recent study conducted by ICF International for the Edison Electric Institute confirms that the Utility MACT rule will trigger the retirement of significant generating capacity and will require new capacity. The study considered the impact of all of the expected EPA rules, including climate-related requirements, and estimated an unprecedented number of environmental control installations and unit retirements across a range of sensitivities. Two scenarios from this study projected the retirement of coal-fired plants with total generating capacity ranging between 56 and 79 GWs by 2015. Several other groups have also examined the impact of EPA's expected rules on coal-fired generation retirements. In an October 2010 report on the impact of EPA's current rulemaking activity, the North American Electric Reliability Corporation (NERC) considered two scenarios, a moderate case and a strict case, for the combined impacts of the Utility MACT, the CATR, the CCB, and the 316(b) regulations. Bernstein Research and Credit Suisse considered the Utility MACT and the CATR regulations. These reports project retirements of plants contributing as much as 70

GWs of generating capacity by 2015. That capacity will need to be replaced to maintain system reliability.

The ICF study also concluded that concurrent with these retirements, 83-100 GWs of scrubbers and 172-194 GWs of fabric filter systems, or "baghouses," would have to be installed by 2015—more than have ever been installed historically (Chart 1, in Appendix). The NERC Report identifies the risk of this construction boom:

> [O]verlapping compliance schedules for the air and solid waste regulations, along with required compliance for rule 316(b) following shortly thereafter, may trigger a large influx of environmental construction projects at the same time as new replacement generating capacity is needed. Such a large construction increase could cause potential bottlenecks and delays in engineering, permitting and construction.

This large number of major projects will result in serious strain on skilled labor pools, commodity markets, engineering expertise, and capital funding, further impairing utilities' ability to meet a three-year MACT compliance deadline.

EPA appears not to take this problem seriously. The major flaw in EPA's analysis is that it makes overly optimistic assumptions about the effectiveness and availability of certain control technologies. Specifically, EPA assumes that Dry Sorbent Injection (DSI) is a one-for-one substitute for the installation of a scrubber. We do not agree with this assumption. A study conducted for the Edison Electric

Institute estimates between 80 and 100 GWs of additional scrubbers will be required versus EPA's assumption of only 26 GWs of additional scrubbers.

In recent rulemakings, the Agency has also greatly underestimated the amount of time required to design, permit, construct, and start-up new pollution control devices, such as flue gas desulfurization units, or scrubbers, and selective catalytic reduction systems (SCR). For example, EPA concluded in the Proposed Transport Rule that it takes 27 months to install a scrubber and 21 months to install SCR. This is counter to industry experience and performance. Southern Company's historical experience, which is the most extensive in the industry, shows it takes an average of 54 months to install a single scrubber retrofit and 36 months to install a single SCR retrofit. Although individual project schedules vary depending on site-specific factors and requirements, none of Southern Company's scrubber or SCR installations has been completed in the timeframes suggested by the EPA. Further, construction timeframes are expected to increase due to logistics of installing multiple controls at a facility simultaneously, industry-wide competition for materials and craft labor, and increasing permitting requirements.

The usual timeframes required for planning, designing, permitting, purchasing, and installing potential control technologies and generation replacement capacity are shown in Chart 2 at the end of my testimony. Based on the industry's historical experience, it is unlikely that all required control technologies will be installed and that adequate replacement capacity will be in place to meet EPA's three-year compliance deadline.

EPA's Compliance Timeline Puts Reliability at Risk

The reliability of the nation's electric generating system is at risk because of the number of new rules and regulations applicable to power plants. The stringency of these regulations, the lack of flexibility likely to be provided within these regulations, and, above all, the compliance schedules that will be required put reliability at risk. Accelerated plant retirements and shutdowns triggered by the Utility MACT rule will cause reserve capacity to plummet, increasing the likelihood and severity of service disruptions.

The NERC report specifically considered the impact of EPA's current and expected rulemakings on electricity reliability. It explains,

> … the impact of reliability is a function of the timeline for finalizing the rules and ensuring compliance with the potential EPA regulations. The reliability impact of these rules will be dependent on whether sufficient replacement capacity can be added in a timely manner to replace the generation capacity that is retired or lost because of the implementation of these rules.

One challenge of complying with these new rules is ensuring adequate reserve margins—that is, generating capacity that is available during times of high demand or during interruptions of service from baseload plants. Bernstein Research data show that over 75 percent of units currently without scrubbers are 200 MW or smaller, more than 60 percent are over 40 years old, and 35 percent have capacity factors of less than 50 percent. These smaller, older units provide critical reliability to the electric grid.

Bernstein Research found that, as a result, "regional capacity margins would be reduced by 7 to 15 percentage points, to 4% in SERC, 6% in SPP, 8% in MRO, and 9% in RFC." With reserve margins in the single-digits, reliability is a major concern. Indeed, the NERC report concludes that "EPA rules may have significant economic impacts on generating units, potentially affecting the reliability of bulk power systems as measured by significant declines in Planning Reserve Margins."

Worse, the operation of EPA's rulemaking will actually impede efforts to address reliability concerns. Bernstein Research projects that, to avoid reliability issues, "a large fraction of the affected plants [will] become subject to reliability-must-run or RMR contracts with their regional transmission organizations (RTOs), thereby ensuring the continued availability of their capacity to the grid." That scenario will be in conflict with the Utility MACT rule and other rules which may not allow regional transmission organizations to call for generation without the necessary controls installed to meet the required limits. This leaves customers at a high risk for experiencing significant electric service interruptions.

EPA's Compliance Timeline Threatens Affordability

The second important issue arising from new environmental regulations is affordability of electricity and the ability of the economy to absorb the cost of massive retrofitting and new capacity projects undertaken on an unprecedented and constrained schedule. The economic impact of controlling or replacing retired coal-fired generation nationwide will range from increased electricity rates and lower discretionary spending, to losses of jobs and tax revenues at power plants and energy-intensive manufacturing, to reliability-related expenses, thus further impeding the economic recovery of the United States.

The EEI/ICF analysis shows that when all pending EPA rules are analyzed, over 150 GWs of coal, half of the U.S. coal fleet, are at risk of being unavailable in 2015 for the needed energy and required reliability due to insufficient time to install controls or replacement generation. Nearly 80 GWs of coal are retired by 2015 and the remaining coal is subject to an unachievable retrofit program. These retirements and retrofits create the need to spend about $300 billion in the next five years, over two thirds of which is for replacement generation. These circumstances lead to generation shortages and a rapid run-up in prices creating a reliability and affordability crisis. Perhaps just as significantly, the breadth of this proposal causes it to overlap with a number of recent and expected EPA rulemakings that affect the utility industry, increasing the complexity and costs of compliance and adding to uncertainty going forward.

Further, with respect to the Utility MACT limits, there is a serious concern that some emission limits are so stringent that current technology does not exist to meet them on all units on a continuous basis. Even where existing technologies are sufficient, the costs of engineering solutions will be significant; development and integration of new technologies will push costs up even more.

Logistical issues due to EPA's aggressive compliance timeline will also contribute to high costs. Attempting to control or retire and replace 400,000 MW in three years will dramatically increase the demand for skilled labor, capital, equipment, and resources. The increasing demands will strain supply, putting upward pressure on compliance costs and increasing the risk of project delays and missed compliance deadlines.

Due to the short compliance timeframe, customers will experience rapid rate increases; large industrial consumers will have little time to adapt their processes; and some energy-intensive business operations may have to permanently close, resulting in job losses. IHS/Global Insight estimates that every $1 billion spent on upgrade and compliance costs will put 16,000 jobs at risk and reduce U.S. GDP by as much as $1.2 billion.

Shutting down coal-fired facilities alone can cost several hundred jobs per facility. The closure of coal-fired plants and large industrial facilities also puts local government finances at risk due to their dependence on tax revenue associated with these facilities. Local governments will have only a short period of time to institute plans for retooling their budgets, retraining the workforce, and determining the extent of the services they can continue to provide.

Finally, the total cost of compliance will remain uncertain even throughout the Utility MACT implementation period, due to current schedules for other final rules and their compliance deadlines The final Utility MACT rules will trigger the need to initiate compliance plans leaving only three years for the impracticable task of overhauling the fleet that provides nearly 50 percent of the U.S. generation. Making early decisions prior to issuance of all of the final rules puts customers at risk for bearing billions of additional costs. Additionally complicating the decision making process and potentially adding costs is the likely litigation of the final rules. The litigation outcome could result in changes to the final rules, but only rarely is litigation accompanied by temporary relief from the requirements the rules impose. Compliance is made more difficult and costly if uncertainty over requirements extends beyond the effective date of the final rules and the compliance deadlines are not stayed.

Protect Reliability and Affordability with a Realistic Compliance Timeline

The solution to the problems created by EPA's unreasonable compliance timeline should be obvious: The industry needs a realistic promulgation and implementation schedule, based on historic experience that reasonably allows it to retrofit units with control technology and begin work on additional capacity. The

Southern Company believes that a minimum compliance timeline is one that would allow upgrades to be made in an orderly fashion without placing reliability in jeopardy or imposing undue costs on electricity consumers.

As discussed above, industry experience demonstrates conclusively that achieving compliance on EPA's three-year timeline is unachievable. When utilities have sufficient advance notice to plan upgrade projects and the required equipment and labor are readily available to complete them, Southern Company's experience shows that installing scrubbers takes, from the planning stage through completion, 40 to 60 months, with an average of 54 months; installing SCR systems takes 28 to 42 months, with an average of 36 months; and installing fabric filter systems takes anywhere from 30 to 48 months. The time necessary to install these types of control systems, as well as others that will prove necessary to comply with the Utility MACT rule, will only be exacerbated by competition within the utility industry for equipment and skilled labor, as well as completion from other industries as they comply with their MACT requirements. While EPA may provide individual units an additional year to comply, the need for extensions will be universal, and even four years will be insufficient to complete required retrofits. EPA's estimation that these projects can be completed in three or four years is not merely optimistic, it is contrary to experience and, as a factual matter, incorrect.

As I have described, the consequences of EPA's unreasonable timetable may be dire. Reserve capacity will dwindle, as multiple plants are taken offline for upgrades, temporarily decommissioned due to non-compliance, or simply retired out of economic necessity. This puts the reliability of our power system at risk, at enormous potential cost. EPA's unreasonable timetable will also inflate the costs of bringing units into compliance, due to the need for expedition at every step of the process, and accelerate spending on new capacity. Customers will face higher rates on average and may, for temporary periods, even experience large price spikes in particular regions. The likely impact on economic growth and jobs will be severe.

The good news is that all of these consequences can be reduced, or even avoided, by extending the rulemaking schedule and the timeline for compliance. We believe that lengthening the implementation period, and retaining EPA's authority to provide an additional one-year extension, will allow for orderly planning, procurement, permitting, construction, and testing and reduce the reliability and affordability risks caused by MACT standards.

Conclusion

EPA's proposed Utility MACT, on its current schedule and in its current form, puts the reliability and affordability of power in the United States at risk. This is due in part to an implementation timeline that is unrealistic and, for that reason, unreasonable. If EPA continues on its present path, the result will be to harm power consumers—which is to say all Americans—and threaten jobs and economic growth. These risks can be reduced or perhaps even avoided by simply slowing promulgation and extending the timeline for compliance. This is a common-sense solution that all stakeholders should be able to support.

I thank the Committee for holding this important hearing today and giving me this opportunity to testify, and I look forward to your questions.

Charts Appendix

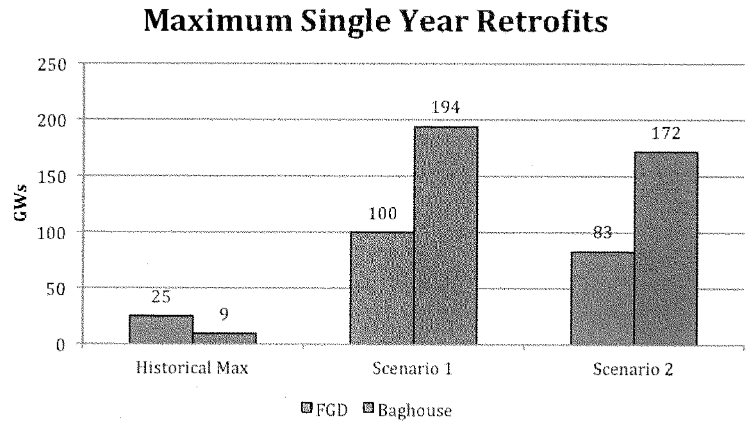

Chart 1: Historical and projected maximum environmental retrofit installations in the U.S. (EEI study conducted by ICF; Historical retrofits Energy Velocity Database 8.24.10).

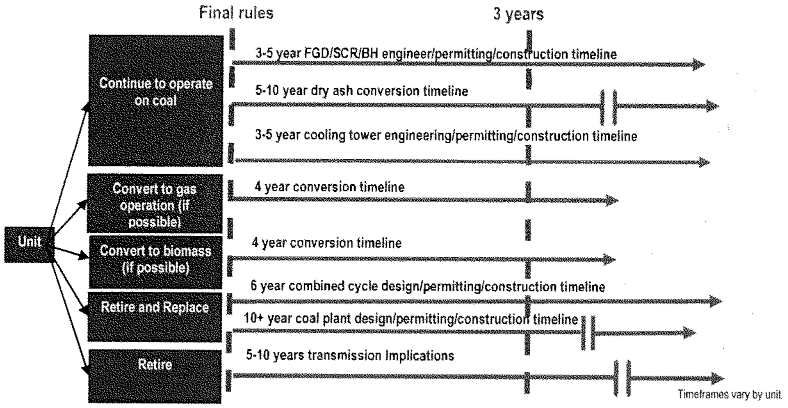
Final rules
3 years
Unit
Continue to operate on coal
Convert to gas operation (if possible)
Convert to biomass (if possible)
Retire and Replace
Retire
3-5 year FGD/SCR/BH engineer/permitting/construction timeline
5-10 year dry ash conversion timeline
3-5 year cooling tower engineering/permitting/construction timeline
4 year conversion timeline
4 year conversion timeline
6 year combined cycle design/permitting/construction timeline
10+ year coal plant design/permitting/construction timeline
5-10 years transmission Implications
Timeframes vary by unit

Chart 2: Time required designing, permitting, purchasing, and constructing environmental compliance options for an individual unit; Does not account for resource competition.

Mr. WHITFIELD. Thank you, Mr. Fanning, and Mr. Earley, you are recognized for 5 minutes.

STATEMENT OF ANTHONY F. EARLEY, JR.

Mr. EARLEY. Thank you, Mr. Chairman and members of the subcommittee for the invitation to address a subject with critical implications for the future of our industry and your constituents, the customers that we serve.

Sometimes we focus too much on what we disagree with, but I want to emphasize one thing that we all should be able to agree on, and that is the importance of a reliable and affordable electric system. We only need to think back to the massive blackout of 2003 to understand the ubiquitous role that electricity plays in our economy and in our personal lives.

Let me start by emphasizing that progress on the environment is vital, but it must continue on a schedule that can be efficiently and cost-effectively managed without requirements that jeopardize the economy and with the sensitivity to preserving the balanced mix of generation technology that has served us so well in the past.

My message today is not do nothing. My message today is to do something that will continue the tremendous progress we have already made. The key to success will be managing the timing, using a commonsense approach to achieve improvements, and ensuring the benefits actually do justify the very real cost in terms of money and jobs.

I want to make it clear why this commonsense measured approach is appropriate by dispelling the myth that we face some immediate environmental crisis. The progress that our industry has made in cleaning the air since the Clean Air Act was adopted in 1970 is one of the great environmental success stories, and I will use my own company, DTE Energy, as an example. Over the last 35 years, we have reduced particulate emissions by more than 90 percent, and sulfur dioxide and nitrogen oxide by more than 70 percent; at the same time increasing generation output by approximately 45 percent. Other electric utilities have accomplished similar results. The bottom line is our children are breathing air today that is far cleaner than the air that we inhaled as children. Having said that, we continue to make improvements. We are investing billions of dollars in environmental controls and clean energy technology.

My concern with the EGU MACT is that it derails this approach and has very serious consequences. The proposed rule is flawed in a number of ways.

First, it provides insufficient time to address these extremely complex issues. This rule will have far-reaching economic and energy supply impacts. Allowing just a 60-day comment period is totally inappropriate. The goal of completing these regulations by November seems equally inappropriate, considering the enormous amount of public comment that this rule is going to generate. Too much is at stake to move forward without proper vetting.

Second, the proposed rule focuses on technology-based standards for some of the emissions, and for some of the emissions, there is sparse data available to support these standards. The EPA is proceeding with regulations under the mistaken belief that reasonably priced technology solutions are currently available to control acid gasses, non-mercury metals, and organics. For example, the low estimate for early plant retirements is based on the belief that the industry can meet acid gas limits using dry sorbent injection. It appears that the EPA made this determination based on one 3-week trial on one boiler type. Even the company that performed that evaluation recommends a more complete trial to better understand the technology. I can't think of any business that would be willing to invest millions or billions of dollars on a single 3-week trial that may or may not be applicable to the entire U.S. coal fleet.

The third and most troubling flaw of the proposed rule is choosing not to pursue health-based standards. The EPA is committing our customers to funding billions of dollars in technology investments without knowing the potential health implications and without serious consideration of the ramifications to the economy and ultimately to the public. EPA's own analysis concludes that reducing the emissions covered by the rules offers only minimal health benefits. Almost all of the benefits they assigned to these regulations is associated with the expected coincidental reductions in particulate emissions, something that is already regulated under another part of the Clean Air Act.

Even if EPA is right about available technology, can we afford to spend billions of dollars when we have no solid understanding of whether it can be worthwhile or not? Whether a conscious decision or not, the regulations will have the impact of driving companies to retire significantly more of their older coal fire units than EPA estimates. With plant closings, lost jobs, and lost tax base at stake, we must be prudent in our decision-making, particularly in this economy.

In closing, I would like to stress that our end goal is the same: continued progress on the environmental front. I ask that you ensure that there is sufficient time for EPA to make sound decisions, to understand whether a health-based standard would reduce the real impacts on our customers and the economy, and to evaluate the adequacy of control technologies so we don't unnecessarily undermine the viability of a diverse energy mix. This approach has served us well in the past, and it will continue to serve us well in the future. Thank you.

[The prepared statement of Mr. Earley follows:]

Recent EPA Rulemakings Relating to Boilers, Cement Manufacturing Plants, and Utilities

Testimony of Anthony F. Earley, Jr.
Executive Chairman
DTE Energy

U.S. House of Representatives Committee on Energy and Commerce
Subcommittee on Energy and Power
The American Energy Initiative
April 15, 2011

Thank you Mr. Chairman and members of the Committee for your invitation to address an important subject, the wave of environmental regulations directed at electric generating units, and specifically about the Electric Generating Unit Maximum Achievable Control Technology (EGU MACT) proposal now pending at EPA. There is probably no more important set of issues because they affect the environment, the availability of reliable, affordable electricity and the economy… each of which is absolutely critical to our future.

I think we can all agree that we must continue the tremendous progress we have made in protecting the environment. We can also agree that electricity is the lifeblood of our economy. We only have to think back to the blackout of 2003 to remember how nearly everything comes to a sudden halt without it. And we can agree that if electricity becomes unaffordable it will hamstring our economy. I have long believed, however, that economic growth and environmental progress are not mutually exclusive. That is the thrust of my comments this morning.

Environmental Progress to Date

I am not here to suggest that we should not continue to make environmental progress. But the MACT rule and the other regulations now being considered by EPA have to be placed in the context of the tremendous progress we have made and continue to make in improving the environment. We have no intention, as some might suggest, of stopping that progress. Unfortunately, some give the impression that rapid adoption is necessary because environmental progress is reversing or has stopped.

Let me take a few moments to review one of the great environmental success stories of all time. In the 1960's and 70's, we truly had deteriorating air quality. But with the foresight of visionaries like my friend Chairman Dingell, the Clean Air Act was adopted in 1970 and significantly amended in 1990. As a result of this historic piece of legislation, our industry and others have made monumental progress in cleaning the air in our country. In particular, at my own company, DTE Energy, over the last 35 years we have reduced particulate emissions by over 90 percent and sulfur dioxide and nitrogen oxide by more than 70 percent. We did this while increasing generation by approximately 45 percent. Other electric utilities have accomplished similar results.

We first focused on the ambient air in the vicinity of the facilities and drove down particulate and sulfur dioxide emissions in the 1970's and 1980's. With the amendments to the Clean Air Act in 1990, we focused even more on sulfur dioxide emissions to address acid rain. In the late 1990's and continuing into the new millennium, we focused on regional impacts, achieving tremendous reductions in nitrogen oxides and even more reductions in sulfur dioxide, addressing ozone and fine particulates. Emission reductions have continued over the last decade. Since 1999, emissions of all of these pollutants in aggregate have declined across Michigan as a result of Clean Air Act programs. Nitrogen oxide and sulfur dioxide emissions have decreased 33 percent and fine particulate more than 40 percent since 1999 from all emission sources in Michigan. The bulk of these reductions are due to the investments that Michigan utilities have made in pollution control technologies in response to Clean Air Act requirements. The ambient air quality has improved significantly. As a result, Southeast Michigan now meets current National Ambient Air Quality Standards for ozone and fine particulate.

The Clean Air Act has served us well and enabled us to achieve great emission reductions and significant improvements in the environment. It has done so while protecting and enhancing the economy. Innovative features -- such as the ability to bank and trade sulfur dioxide allowances under the Acid Rain program, which was developed in cooperation with the Environmental Defense Fund -- resulted in achieving the Act's goals at costs that were far below expectations. The Act also adopted reasonable time frames for implementation that did not unnecessarily drive up costs or jeopardize the reliability of the electric system. Thus, the key to success of any environmental initiative is in managing the timing and using a common sense approach to achieving improvements.

Let me re-emphasize: there is more to accomplish, but we are only requesting that the management approaches and reasonable timing applied in the past be applied in this new wave of regulations.

If we ignore the lessons of the past, we risk stalling our economic recovery. In Detroit, we are particularly mindful of the urgency of getting our economy back on track and getting people back to work. Times of great challenges are also times of great opportunity. Congress must ensure in those times we properly balance the strategic importance of energy with the appropriate pace and cadence of environmental improvements.

Wave of Environmental Regulations

I know that today's focus is the EGU MACT, but it is essential to note that it is only one of many environmental regulatory proposals focused on the electric industry. As an industry, we have said this before, we face a potential regulatory "train wreck." We use that term because we believe with the right policy decisions we can keep the train on the track while continuing to achieve great progress – in terms of the environment, energy and the economy. Without the right policy, we could be headed for disaster.

We are an industry that must plan at least a decade ahead and think many decades ahead. When a decision is made to build a power plant today, that decision will have implications well into the second half of this century. In my state, today's fleet of power plants has an average age of roughly 50 years. When those decisions were being made, no one had ever heard of global warming, there was plenty of cheap oil to fuel power plants as well as cars, there were hardly any nuclear plants, and natural gas was flared at the wellhead because of limited transportation infrastructure. In the intervening half century, events have yanked energy policy in many directions. Fortunately one of our industry's pole stars has been the need to diversify our fuel supplies. While short-term events naturally move us in different directions, we cannot abandon viable generation assets too abruptly. Unfortunately, that principle is more easily stated than followed. In the late 1970's and into the 1980's, following Three Mile Island and with the economic downturn, the industry acquiesced in the face of numbing public fear and increased regulatory demands and turned away from nuclear energy. We slowed building any new coal units. As a nation, we even banned the use of natural gas as a boiler fuel in the Fuel Use Act of 1978. Facing high interest rates for new plant construction, we focused on maintaining existing coal units, many of which were built in the 1950's and 1960's. This resulted in older units operating longer than many had predicted.

When the economy rebounded in the 1990's, the demand for reliable, affordable power also increased. Policy and economics pointed the industry toward natural gas-fired units, which were no longer prohibited. And while these plants have attractive environmental characteristics, the demand for natural gas led to spikes in natural gas prices. When prices spiked, those brand new gas fired plants were priced out of the market -- no one could afford their electricity. Many of them have sat idle for the better part of a decade.

We are now at another crossroad. The economic recovery, while still fragile, is starting to get some traction and will lead to renewed demand for power. This demand growth will run headlong into our common desire to push for continued significant emission reductions, and the desire to address additional environmental concerns and renewed sensitivity to nuclear power. It is vital that we remember that a diverse supply of energy has served us well in the past and will be equally important in the future to maintain our energy security and maintain competiveness in the marketplace. We need to continue to drive energy efficiency to the extent practicable. We need to continue to promote the development of renewable energy sources. We need to learn the lessons of Fukushima, but America must continue to move forward with our nuclear energy plans. We need to be able to utilize coal, our most abundant fuel, better and cleaner than anyone in the world, because coal will be used by others for a long time to generate electricity. We also need to include natural gas as a significant player in our electricity future as we develop the abundant reserves of shale gas.

Because electricity is essential to our quality of life, we must be an industry that is totally focused on meeting our customers' needs for affordable and 100 percent reliable electricity. We must not let the current wave of environmental regulations focused on electricity generation -- the transport rule, the EGU MACT, cooling water intake (or 316b) regulations, coal ash regulations, and climate change -- to prematurely shut down coal generation, without a clear transition strategy, and in some cases with little or no corresponding environmental benefit. We are especially concerned about the narrow compliance window associated with some of these regulations, particularly the EGU MACT. We believe it will result in more short-term thinking and approaches that will cost our customers much more in both the near and long term. This is a result that we know our customers in Detroit cannot afford.

Although most of the regulations are not yet final, our analysis and that of many others show that the regulations will drive Detroit Edison and many companies in the Midwest and Southeast to retire up to 20-30 percent of our existing coal fired capacity over a short period of time. This will result in job losses and reduced tax base for many communities. When plants are rushed into retirement, jobs disappear. When plants are rushed into retirement, local tax base shrinks. This will come at a time when many communities across the country – but especially in the Midwest and Southeast – are continuing to struggle with high unemployment and declining local tax revenues.

Utilities in Michigan and other states are driving significant energy efficiency gains and increasing our generation from renewable sources, but we believe much of the base-load generation that replaces retiring coal facilities will need to be natural gas-fired.

We are concerned that a rapid escalation in demand for natural gas-fired electricity generation could drive another natural gas price spike. This is something we know our electric and natural gas customers in Detroit simply cannot afford.

While shale gas has significantly expanded our natural gas reserves, history tells us that natural gas prices will, in fact, spike in the face of increased demand. Given the time delay in conducting new drilling and the challenge of building new pipeline infrastructure, we rarely have an exact match of supply and demand. Moreover, we know from history that there are no silver bullets in the energy field. Nuclear was going to be too cheap to meter. We were the Saudi Arabia of coal, oil was less than $10/ barrel. Shale gas, while a tremendous new resource, will likely be slowed by concerns about drilling and infrastructure development. Let's not put all our eggs in that basket. Over the long term, we believe that the natural gas supply system will be better able to manage this increase in the use of natural gas for electricity generation. It would be an economic mistake to rush that day by artificially abandoning coal resources. I am not asking to back away from the environmental progress that the regulations are intended to achieve. Rather, I am advocating an approach that minimizes the financial impact on our customers, many of whom are still struggling with the effects of the Great Recession.

Our commitment to environmental progress is demonstrated by what we've done and what we are doing. We have and are partnering with our customers to drive energy efficiency. DTE Energy has invested $1.7 billion on state-of-the-art emissions control equipment at our Monroe Power Plant. We're investing hundreds of millions dollars more in additional controls at that facility and other plants in our fleet. We recently announced an $800 million upgrade at the Ludington, Michigan, Pumped Storage facility that we co-own with Consumers Energy. We're on a path to spend up to $2 billion on clean, renewable, wind energy farms in our state. In a state with the economic challenges we face in Michigan, these are huge investments. We know there is more to do, but we must pace these investments that our customers must finance.

I know there are some who argue that this wave of regulations can drive new industry and create many jobs. That may well be true in the future, but we know with certainty it will eliminate real jobs today and inflate wholesale power prices, driving up costs for many. We are at a time of transition and transformation in the electric industry. We recognize it. This committee recognizes it, as evidenced by its interest in examining the benefits of new-generation nuclear power plants, R&D into carbon-capture and storage technology, and the continued development of our country's renewable energy resources.

It is not an easy balance to achieve, but I believe it can be done because we've done it before. Congress can and should act to adopt policies that balance continued environmental progress with minimizing adverse economic impacts on businesses and households struggling to pay their bills.

EGU MACT Specific

Let me now shift to a few EGU MACT specific comments. First, we believe that providing only a 60-day comment period for such a complex rule, one that will have far-reaching economic and energy supply impacts, is totally inappropriate.

The duration of the comment period appears to be driven solely by an arbitrary court settlement date to which the EPA voluntarily agreed. Those of us with the most at stake and the best sense for the impacts on customers had absolutely no input on the timing issue. This date required the rule to be proposed while emissions data collected over the previous year and submitted to EPA was still being evaluated and analyzed. Less complex proposed regulations with significantly less potential impact have received significantly more time for EPA analysis and public input.

Additionally, the goal of completing these regulations by November of this year seems equally outrageous and arbitrary. If the response to EPA's Industrial Boiler MACT and early response to the EGU MACT is any indication, EPA will receive an enormous amount of public comment which will deserve EPA's serious consideration and evaluation. It is not credible to expect that EPA can effectively evaluate substantial public comments, make appropriate revisions to the proposed rule, and issue a reasoned and appropriate final rule by November. We are very supportive of continuing the environmental progress we have made in this country. We just ask that the progress be balanced with the need to promote the economic recovery and take care of our struggling customers.

We have been talking about regulating hazardous air pollutants for electric generating units for some time and EPA's past record has indicated that the only significant hazardous air pollutant of concern from power plants was mercury. In fact, many states, including Michigan, already have promulgated regulations directed at reducing mercury emissions from electric generating units and we have plans and equipment under construction to meet this requirement. This is not the case for the other hazardous air pollutants that the EPA has chosen to regulate at this time – acid gases, non-mercury metals, and organics, that require pollution control equipment beyond what is needed to reduce mercury emissions. The extremely short time frames and the extremely stringent emission limits and control technology requirements make this rule particularly burdensome to us and our customers. This is particularly troublesome because there is scant evidence that health concerns have prompted the need for regulating these emissions. It appears that almost all of the benefit assigned to these proposed regulations is associated with expected reductions in particulate emissions, something regulated by other parts of the Clean Air Act, most specifically the Transport Rule and particulate matter national ambient air quality standard, which was last tightened in 2006 and which will be further tightened next year.

The EPA is proceeding with these EGU MACT regulations under the mistaken belief that it is quite easy to control these emissions. For example, it has staked its estimate of minimal early plant retirements on their belief of the industry's ability to meet the acid gas limits with the application of dry sorbent injection (DSI). It appears that the EPA makes this determination based on one three-week trial test. Interestingly, the company that reported on this study states that they "recommend completing a trial to understand the system, fuel, and pollutants interaction." In other words, there is much testing that is necessary to determine where and to what extent this technology will help meet the standards.

I cannot think of any business that would be willing to invest the required hundreds of millions – perhaps billions – of dollars on the basis of a three-week trial. With this sparse data, it is impossible to assess the effectiveness of DSI across all types of fuels and boiler designs. This will require significant unit-specific testing to determine its broader viability.

Based on its minimal and insufficient information, the EPA projects the early retirement of 10 GW of capacity. It is expected, however, that many of these units will need to install wet flue gas desulfurization (FGD) to meet these emission standards. If that is the case, other studies show that early generation retirements will be in the 25-80 GW range. Given the short comment period, it's almost impossible to test whose hypothesis is right.

This is particularly troubling since this is supposed to be a technology-based rule. The EPA has chosen not to make use of a provision in the existing Clean Air Act that allows them to utilize a health-based standard rather than a technology standard. They claim that there is not enough information or time to utilize the health-based standard. Isn't that one of the very issues at hand? Just because reduction technologies may be available, which we don't concede, why spend money just because it might have some benefit. How wise is it to subject an industry so critical to America's way of life, its standard of living, and its economic vitality to billions of dollars of additional costs because the regulating agency does not choose to the take the time to produce a more reasonable approach? In fact, if EPA were willing to take the time to analyze the appropriate data, EPA's own analysis shows that acid gas emissions from coal-fired power plants do not result in exceedances of any Reference concentration established by EPA or the Electric Power Research Institute (EPRI). EPRI has modeled every coal-fired power plant's acid gas emissions and provided the EPA with adequate factual information to set an alternative health-based standard. This approach could reduce the financial impact on the customers while also assuring their protection.

As indicated earlier, it is also interesting that the EPA appears to attribute almost all of the expected health and environment benefits of this proposal to expected reductions in fine particulates (PM 2.5), a criteria pollutant which is managed by other provisions in the Clean Air Act, not to the reduction in hazardous air pollutants. Put another way, EPA's own analysis appears to conclude that the EGU MACT offers only minimal, at best, health-based benefits from reducing the hazardous air pollutants it is supposed to address, such as mercury and acid gases.

While we and others will submit detailed comments on this proposal, let me finish with some observations on the operation of our units during startup and shutdown and how these regulations will drive expenditures beyond what should be necessary. The EPA proposes to require emissions that occur during startup, shutdown and malfunction to be included in meeting these proposed standards. The emission standards were established using data collected under steady-state conditions, when the emission control equipment is designed to operate optimally. Although we have tremendous operators, under conditions of startup, shutdown and malfunction, the applicable control equipment does not, by design, operate at its maximum performance.

The result of this overly stringent approach is to effectively establish a more stringent limit than appears in the regulations, because operators must over-comply during normal operations to "make up" for the higher emissions that will undoubtedly occur during startup, shutdown and malfunction. A work practice standard applied during plant startup and shutdown, specific to the unit's boiler type and control equipment, would be more appropriate. Again, we need to use some common sense.

Finally, the proposed emission limits for new coal plants are so strict as to be below the ability of monitors to measure such concentrations and beyond the ability of control technologies to reduce the emissions as required. Even if CCS is proven, these MACT limits for new coal plants might eliminate the possibility of new coal plants.

Possible Solutions

Whether a conscious decision or not, this wave of regulations in general and the stringency of the EGU MACT in particular will have the impact of driving companies to retire many of their older, coal-fired units. This initiative has the potential to impact struggling regions of the country, such as Michigan and the Midwest, more severely than other regions that rely less on coal-fired generation. It is imperative that Congress cushion the impact on customers in these regions while still assuring the ultimate outcome in reductions of hazardous and other air pollutants.

This can be achieved by implementing a process that allows companies and communities more time to plan for the potential loss in generation capacity, the resulting loss of tax revenues, and the potential impact on community services. The three years or less that is provided for in the EGU MACT proposal is not designed to address these sorts of outcomes. Time is valuable.

Several options could be considered that would produce more rational outcomes. For example, utilities could be granted the flexibility to retire a unit by a date certain, possibly ten years, and exempt that unit from new regulations (but still required to meet existing regulations and thus not allowed to backtrack). The benefits of such an approach include minimizing the customer impact from both financial and reliability concerns. It would also provide better certainty in the planning process that should be occurring in the industry. And, it would assure 100 percent emission reductions from units that commit to retire by a date certain.

For units not retiring – those essential to continue supplying the needed electricity – it is recommended that Congress and the Administration consider limiting or adequately pacing emission control equipment requirements. For example, mercury reductions are already being planned and could continue to be required by the 2015-16 time period. It is recommended that the EPA adopt a provision that is included in the Michigan mercury rules that requires no further mercury reductions for units equipped with a selective catalytic reduction (SCR) unit and a flue gas desulfurization (FGD) unit in combination. This encourages greater reduction in nitrogen oxides and sulfur dioxide emissions and likely similar reductions in mercury without burdening our customers with significant additional cost for incremental benefit.

Congress could also allow companies to plan control equipment installations by dates certain but spread the financial impact on our customers over a more reasonable time. For example, it could require 50 percent of the remaining generation to be controlled by 2015, 75 percent by 2018, and 100 percent by 2020.

For acid gases, Congress could mandate EPA to allow units the ability to demonstrate that they are meeting a health based standard rather than a technology driven standard based on a far from proven process. As stated earlier, this opportunity is already provided for in the Clean Air Act and supported with existing data, but not allowed in the proposal.

Regarding the non-mercury metals, Congress could require EPA to make the EGU MACT more consistent with the Industrial Boiler MACT and demonstrate compliance by meeting a filterable particulate standard, which is directly measured by existing continuous emission monitoring equipment, rather than a total particulate standard. It appears that this provision is not necessary to demonstrate reductions of the non-mercury metals.

Finally, it is recommended that compliance with the non-mercury metal limits be based only on demonstrating compliance with the specified particulate limit, 0.03 pounds/MMBtu and eliminate the provision that limits would be lowered if the actual operational results were lower. It appears that this penalizes greater reduction efficiencies of particulate control equipment and only drives greater costs to our customers.

Conclusion

To conclude, I want to emphasize that my message today is not "Do nothing." I firmly believe that progress on the environment needs to continue. But it needs to continue in a rational way. It needs to continue at a pace that can be efficiently and cost-effectively managed. It needs to be continued in way that provides measurable environmental and health benefits while not jeopardizing the economy. And it needs to be in a way that preserves a balanced mix of generation technologies that has served us well in the past and will continue to serve us well in the future.

Thank you.

Mr. UPTON [presiding]. Thank you, Mr. Earley. Mr. Bradley?

STATEMENT OF MICHAEL J. BRADLEY

Mr. BRADLEY. Good morning, Chairman——

Mr. UPTON. You need to hit that mic button down below.

Mr. BRADLEY. Good morning, Chairman, Ranking Member Rush, and members of the subcommittee. My name is Michael Bradley, the executive director of The Clean Energy Group. I am testifying today on behalf of The Clean Energy Group's Clean Air Policy Initiative, a coalition of electric power companies. The member companies are some of the Nation's largest generators of electricity, serving nearly one-fifth of all U.S. electric customers. On behalf of my member companies, I appreciate the opportunity to speak with you today and offer the following observations on the proposed Utility Toxics Rule.

The rule provides the business certainty required for the industry to move forward with capital investment decisions. The proposal, while not perfect, is reasonable and consistent with the requirements of the Clean Air Act. The electric sector, overall, is well-positioned to comply. The Clean Air Act provides sufficient time to comply, as well as the authority to accommodate special circumstances where additional time is necessary.

It should be no surprise that EPA issued this rule. Since 2000, the electric industry has known that hazardous air pollutants would be regulated under the Clean Air Act. Now, over a decade later, EPA is under a quarterly deadline to finalize the rule by November. Additionally, EPA conducted an extensive data collection effort with the cooperation of industry to ensure that the standards were based on real world operating experience.

The proposed standards are not as burdensome as some electric sector members anticipate. In fact, if there was any surprise, it was the degree of compliance flexibility proposed by the rule. For example, the proposal includes work practice standards for dioxins rather than initial limits, surrogates for certain hazardous air pollutants, as well as the ability to average among units at a facility. We are evaluating specific technical issues with the rule that we think need to be addressed, but we expect continued engagement with EPA will lead to a final rule that is both balanced and flexible.

The technologies to control hazardous air emissions, including mercury and acid gasses, are commercially available. Also, the industry has extensive experience with installation and operation of these controls. Companies will generally have 3 years to comply once the rule is final. We believe that the vast majority of generating units can meet this schedule for several reasons.

First, to their credit, many companies have installed major components of pollution control systems that will be required to comply. For example, 60 percent of the Nation's coal capacity has already been retrofit with scrubbers. We are not starting from scratch.

Second, EPA allows compliance flexibility in the rule by allowing power plant owners to average their emissions across all the boilers at a facility. Almost 20 percent of coal capacity that currently lacks scrubbers is co-located at plants with existing scrubbers for the potential to average.

Third, historic experience shows that the industry has the capacity to install a large number of pollution control systems in a relatively short period of time. Between 2008 and 2010, the industry installed about 60 gigawatts of scrubbers and 20 gigawatts of advanced NOx controls.

Fourth, most of the controlled technologies that will be required to comply, like activated carbon injection and dry sorbent injection, can be installed in less than 2 years. If a company is unable to comply in time, the Act allows up to one additional year to install the necessary controls. This will allow companies to manage multiple control installations and avoid potential reliability concerns. Furthermore, EPA has the authority and has used this authority in similar situations to provide additional time beyond the 1-year extension.

To conclude, the Clean Air Act amended by Congress in 1990 with overwhelming bipartisan support and signed by George H.W. Bush requires regulations that limit hazardous air pollutions from the electric sector. In 2000, EPA took the first step towards regulating those emissions, and over a decade later, EPA now is working to finalize the rule. While complying with these obligations will require planning and significant resources, many companies are on their way to complying. There is no reason to delay the implementation of the Utility Toxics Rule. Proceeding on schedule with the flexibility that is available will provide the business certainty that the industry is looking for.

Thank you for your time, and I would welcome any questions you may have.

[The prepared statement of Mr. Bradley follows:]

Summary of Testimony of Michael J. Bradley, President, M.J. Bradley & Associates LLC and Executive Director of the Clean Energy Group before the U.S. House of Representatives Committee on Energy and Commerce Subcommittee on Energy and Power

April 15, 2011

On behalf of the Clean Energy Group's Clean Air Policy Initiative members, I appreciate the opportunity to addresses the National Emission Standards for Hazardous Air Pollutants from Coal- and Oil-fired Electric Utility Steam Generating Units (the "Utility Toxics Rule") released by EPA on March 16, 2011. The rule will establish, for the first time, federal limits on emissions of mercury and other hazardous air pollutants from power plants. I will offer comment on the following four issues:

- The Utility Toxics Rule provides the business certainty the electric sector needs to move forward with capital investment decisions;
- While not perfect, the proposal is reasonable and consistent with the requirements of the Clean Air Act;
- The electric sector is well positioned to comply; and
- The Clean Air Act provides sufficient time to comply as well as the authority to accommodate special circumstances where additional time is necessary.

The Clean Air Act requires EPA to implement regulations to control the emissions of hazardous air pollutants from the electric sector. In 2000, EPA took the first step toward regulating those emissions, and over a decade later, EPA is now under a court-ordered deadline to finalize the rule by November 2011. While complying with these obligations will take planning and significant resources by the electric sector, many companies are well on their way toward compliance and, based on the proposed rule, we anticipate that the electric sector can comply with the Act's requirements. There is no reason to delay the implementation of the Utility Toxics Rule.

Testimony of Michael J. Bradley, President, M.J. Bradley & Associates LLC
Executive Director of the Clean Energy Group

before the

U.S. House of Representatives Committee on Energy and Commerce
Subcommittee on Energy and Power

Hearing on
"The American Energy Initiative"
regarding
Recent EPA Rulemakings Relating to Boilers, Cement Manufacturing Plants, and Utilities

April 15, 2011

Good morning, Chairman Whitfield, Ranking Member Rush, and Members of the Subcommittee. My name is Michael Bradley, and I am the President of M.J. Bradley & Associates LLC and the Executive Director of the Clean Energy Group.

The Clean Energy Group's Clean Air Policy Initiative is a coalition of electric power companies dedicated to responsible energy and environmental stewardship. The member companies are some of the nation's largest generators of electricity, with over 200,000 megawatts (MW) of electric generating capacity, including 105,000 MW of fossil fuel fired capacity, throughout the U.S. Our members serve nearly a fifth of all U.S. electric customers. The members include Austin Energy, Avista Corporation, Calpine Corporation, Constellation Energy, Exelon Corporation, National Grid, New York Power Authority, NextEra Energy, PG&E Corporation, Public Service Enterprise Group, Inc., and Seattle City Light.

On behalf of our member companies, I appreciate the opportunity to address the National Emission Standards for Hazardous Air Pollutants from Coal- and Oil-fired Electric Utility Steam Generating Units (the "Utility Toxics Rule") released by EPA on March 16, 2011. The rule will establish, for the first time, federal limits on emissions of mercury and other hazardous air pollutants from power plants. I will offer comment on the following four issues:

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Proposed Utility Toxics Rule Provides Needed Business Certainty for Long-Term Investments and Advanced Planning

Overall, the Utility Toxics Rule proposal is balanced and reasonable, and individual companies are continuing to work with EPA on specific aspects of the rule. Importantly, the rule provides the business certainty needed for companies' long-term investment decisions – something for which the industry has collectively advocated. This proposal, combined with the Transport Rule, provides the electric sector a road map for long-term investment decisions related to the Clean Air Act.

It is no surprise that EPA has issued this rule. Since 2000, the electric industry has been anticipating that EPA would regulate hazardous air pollutant emissions. In 2005, EPA finalized the Clean Air Mercury Rule, but legal challenges were quickly filed, and the D.C. Circuit ultimately vacated the rule in 2008. In 2009, EPA entered into a consent decree that requires the Agency to finalize a rule by November 16, 2011, regulating all hazardous air pollutants emitted by coal- and oil-fired generating units.

In developing the proposed rule, EPA conducted an extensive data collection effort with the cooperation of industry. More than 300 coal-fired generating units conducted stack emissions testing in support of the rule. The Clean Air Act requires that the standards be based on the best performing power plants in the industry. Thus, the proposal is based on standards of performance that are already being achieved by existing power plants.

Now that the proposal has been released, companies can begin, if they have not done so already, the planning and preliminary engineering studies to identify the necessary control technologies. In fact, as I will explain later in my testimony, many companies, even before the rule was proposed, have been installing advanced controls, developing compliance strategies, testing alternative control options, conducting preliminary engineering studies, establishing capital budgets, and signing contracts with pollution control vendors. For example, the Institute of Clean Air Companies (ICAC), a national association of companies providing pollution control systems for power plants and other stationary sources, has reported about 55,000 MW of new bookings for advanced mercury controls.[1]

Proposed Standards are Reasonable

The proposed standards are not as burdensome as some in the electric sector had anticipated. About 50 percent of coal-fired generating units that submitted data to EPA are already achieving the proposed mercury standard, and about 70 percent of coal-fired units in that same database are already achieving the proposed particulate standard.

In fact, if there was any surprise, it was the degree of compliance flexibility proposed by the rule. The proposal includes "work practice standards" rather than emissions performance standards for dioxins and furans, and uses "surrogates" for certain hazardous air pollutants. EPA also proposes a 30 day averaging period in demonstrating compliance with the standard for coal-fired power plants. Finally, EPA has proposed to allow averaging among units at a facility. The Clean Energy Group and other companies are in the process of evaluating specific challenging technical issues, but we anticipate that continued engagement with the industry by EPA will lead to a final rule that is balanced and flexible, allowing the industry to comply.

Technologies to Comply with the Proposed Rule are Available and Cost Effective

The technologies to control emissions from coal-fired power plants, including mercury and acid gases, are available and cost-effective. There are a range of control technology options that are commercially available to comply with the rule, and the industry has extensive experience with the installation and operation of these control systems.[2] In fact, as I mentioned, many companies have already taken steps to install control technologies that will allow them to comply with requirements of the rule on time.

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[1] Northeast States for Coordinated Air Use Management, *Control Technologies to Reduce Conventional and Hazardous Air Pollutants from Coal-Fired Power Plants*, March 31, 2011, at p.2.
[2] Id.

Several of the Clean Energy Group companies have already installed, or are in the process of installing advanced controls, that they anticipate will allow them to comply with the Utility Toxics Rule. For example, Constellation Energy, a member of the Clean Energy Group, recently installed a major air quality control system, including scrubbers, a baghouse, and other equipment at its Brandon Shores facility in Maryland. Construction was completed in 26 months and employed nearly 1,400 skilled workers.

Experiences similar to Constellation's indicate that, on the whole, the industry can comply with the proposed rule in a timely and cost-effective manner. The costs associated with compliance are important to recognize, but it is equally important to put those costs into perspective. The U.S. electricity industry is one of the most capital-intensive industries in the U.S. – traditionally investing between $80 and $110 billion per year on capital infrastructure projects.[3] The costs to comply with the Utility Toxics Rule will comprise only a fraction of this amount. Moreover, as the installed equipment is then depreciated over 25 to 40 years, the impact for utility customers associated with these investments is spread over a long period of time, and are not incurred in a single year.

Additionally, compliance with the Utility Toxics Rule comes at a time of low natural gas prices, and investment in load management alternatives such as energy efficiency and demand response can further lower the cost of compliance. Most experts agree that natural gas prices will likely remain low for many years; therefore, any rate increases from compliance with the Utility Toxics Rule will occur while lower fuel costs continue to place downward pressure on utility rates.

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[3] See, e.g., Credit Suisse Report, *Growth from Subtraction*, September 23, 2010, at p.42; EEI, *Construction: Q2 2010 Financial Update*, 2009, at p.1; U.S. Census, *Annual Capital Expenditures Survey*, 2009 (Available at: http://www.census.gov/econ/aces/xls/2009/summary_of_findings.html).

The Clean Air Act Provides the Necessary Time to Comply with the Act

In general, companies will have three years to comply with the Utility Toxics Rule. We believe that the vast majority of generating units can meet this schedule for several reasons.[4]

First, to their credit, many companies have already installed major components of the pollution control systems that will be required to comply with the standards proposed by the rule. For example, 60 percent of the nation's coal capacity has already been retrofit with scrubber controls. Among large coal-fired generating units – primarily baseload coal units greater than 400 MW– more than 70 percent have scrubbers installed. Additionally, many coal plants have already installed advanced mercury controls, high efficiency particulate controls, and other control systems that will facilitate their compliance with the rule. Thus, the generating fleet as a whole is well on its way to being in a position to meet the requirements of the Utility Toxics Rule. We are not starting from scratch.

Second, EPA allows compliance flexibility in the rule by allowing power plant owners to average their emissions across all of the boilers at a facility. A company can over-control at some of its units and under-control at others, but still comply with the rule. Almost 20 percent of coal capacity that currently lacks scrubber controls is co-located at plants with existing scrubbers. These units can potentially benefit from the averaging provisions of the rule, resulting in lower capital investments, and in some cases those investments will be substantially lower.

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[4] See, e.g., URS Corporation, *Assessment of Technology Options Available to Achieve Reductions of Hazardous Air Pollutants*, April 5, 2011; Northeast States for Coordinated Air Use Management, *Control Technologies to Reduce Conventional and Hazardous Air Pollutants from Coal-Fired Power Plants*, Press Release, March 31, 2011 (quoting Dr. James Staudt of Andover Technology Partners, who concludes that "[t]he owners of coal-fired power plants have a range of technologies available to them to meet the demands of air pollution control regulations. Over the last ten years the industry has demonstrated tremendous skill in installing advanced pollution controls on existing units, and this was in part due to good planning by utilities in anticipation of those regulations. With this in mind, I am confident that the industry is capable of meeting the requirements of the Air Toxics Rule in the three year time frame required by the Clean Air Act." See also, Letter from David Foerter Executive Director, ICAC to Senator Carper, November 3, 2010 (available at: http://www.icac.com/files/public/ICAC_Carper_Response_110310.pdf) (highlighting that "labor availability has never jeopardized overall industry compliance requirements, nor is there any reason to assume that it would prevent the power generation industry from effectively complying in a timely way with requirements.")

Third, historic experience shows that the electric power sector has the capacity to install a large number of pollution control systems in a relatively short period of time. Between 2008 and 2010, the industry installed about 60 gigawatts (GW) of scrubbers and 20 GW of advanced NOx controls.[5]

Fourth, most of the control technologies that will be required to comply with the Utility Toxics Rule – like activated carbon injection and dry sorbent injection – can be installed in less than two years.

Again, we believe the vast majority of power plants can meet the three year compliance schedule. However, if a company is unable to comply in time, the Clean Air Act allows up to one additional year to install the necessary control technologies. In fact, this authority is highlighted in the proposed rule, and we expect that the Clean Energy Group companies and others will offer recommendations to EPA that should determine when companies are eligible for additional time. The option of requesting an additional year for compliance is an important tool for companies to manage multiple control installations and avoid any potential reliability concerns. Clear and consistent criteria that reflect a good faith effort to comply within three years along with a specific compliance schedule is a reasonable approach for the limited number of special cases that need additional time. In the end, if this process proves insufficient for a specific unit, EPA has the authority to enter into a consent decree with that company for additional time. This process has been effective in the past when needed, but more often than not industries have been able to comply with the requirements set forth in the Clean Air Act.

Questions about whether there is sufficient time to comply have also been raised in the context of reliability concerns. However, we do not believe compliance with the rule will compromise the reliability of the electric system.[6] The U.S. bulk power system, at an aggregate level, has adequate spare capacity to absorb potential retirements. The U.S. electric sector is expected to have more than 100 GW of surplus generating capacity over target reserve margins – one of several important indicators of electric system reliability. This surplus is almost three times the 25 to 40 GW of retirements projected by industry analysts. Moreover, many of the uncontrolled units, which are most likely to retire, are smaller, inefficient units and companies are already making retirement decisions independent of the Utility Toxics Rule due to fundamental economics.

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[5] Letter from David Foerter Executive Director, ICAC to Senator Carper, November 3, 2010 (available at: http://www.icac.com/files/public/ICAC_Carper_Response_110310.pdf)

[6] See, e.g., M. J. Bradley & Associates, LLC and Analysis Group., *Ensuring a Clean, Modern Electric Generating Fleet while Maintaining Electric System Reliability*, 2010 (Available at: http://www.mjbradley.com/documents/MJBAandAnalysisGroupReliabilityReportAugust2010.pdf); Ira Shavel and

Further, the electric industry has a proven track record of adding additional generating capacity and transmission solutions when and where needed and of coordinating effectively to address reliability concerns. In the three years between 2001 and 2003, the electric industry built over 160 GW of new generation—about three to four times what analysts project will retire over the next five years. Existing gas units also have significant untapped power production potential, which can be utilized without constructing new generation. This underutilized capacity can also assist in managing power plant outages required to install pollution control systems. For example, natural gas facilities in the Midwest and Southeast – with average capacity factors of only 20 percent – have significant potential to increase their output. These are the regions that are likely to see the most retirements.

In the end, if there are specific local reliability concerns, state and federal regulators have an array of tools to moderate impacts on the electric system, where necessary. We released a report last August with the Analysis Group aimed at starting the discussions needed among EPA, the industry, and other agencies to ensure advanced planning occurs. Tools that have been deployed successfully in the past include reliability-must-run contracts, adjusting unit maintenance schedules, signing up additional interruptible supply contracts, and coordinating closely with neighboring power systems to maximize power purchases.

Barclay Gibbs, Charles River Associates, *A Reliability Assessment of EPA's Proposed Transport Rule and Forthcoming Utility MACT*, 2010 (Available at: http://crai.com/uploadedFiles/Publications/CRA-Reliability-Assessment-of-EPA%27s-Proposed-Transport-Rule.pdf).

Conclusion

To conclude, the Clean Air Act requires EPA to implement regulations to control the emissions of hazardous air pollutants from the electric sector. In 2000, EPA took the first step toward regulating those emissions, and over a decade later, EPA is now under a court-ordered deadline to finalize the rule by November 2011. While complying with these obligations will take planning and significant resources by the electric sector, many companies are well on their way toward compliance and, based on the proposed rule, we anticipate that the electric sector can comply with the Act's requirements. There is no reason to delay the implementation of the Utility Toxics Rule.

Thank you for your time. I have attached the reports cited in my testimony, and I would welcome any questions you may have.

Attachments to Testimony of Michael Bradley, President, M.J. Bradley & Associates LLC Executive Director of the Clean Energy Group before the U.S. House of Representatives Committee on Energy and Commerce Subcommittee on Energy and Power

April 15, 2011

Control Technologies to Reduce Conventional and Hazardous Air Pollutants from Coal-Fired Power Plants

March 31, 2011

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Control Technologies to Reduce Conventional and Hazardous Air Pollutants from Coal-Fired Power Plants

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March 31, 2011

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Executive Summary

To implement requirements adopted by Congress in the federal Clean Air Act (CAA), the U.S. Environmental Protection Agency (EPA) is developing new rules to reduce air pollution from fossil fuel power plants. Power plants that burn coal will bear a large responsibility for reducing their emissions further, as the majority of air pollutants from the electric generation sector come from coal combustion.

The major rules addressing power plant pollution that EPA recently proposed are the Clean Air Transport Rule (Transport Rule), and the National Emission Standards for Hazardous Air Pollutants from Electric Utility Steam Generating Units (Air Toxics Rule). The Transport Rule will address the long-range interstate transport of sulfur dioxide (SO_2) and nitrogen oxides (NOx) in the eastern United States. Both these types of pollutants contribute to formation of small particles ("fine particulates") in the atmosphere that can be transported long distances into downwind states. These small particles can be inhaled deep into the lungs, causing serious adverse health impacts. Nitrogen oxides also contribute to the formation and long-range transport of ground-level ozone, another pollutant with significant health impacts. The Air Toxics Rule will address emissions of hazardous air pollutants (HAPs) such as mercury, lead, arsenic, along with acid gases such as hydrogen chloride and hydrogen fluoride and organic air toxics (e.g., dioxins and furans). HAPs are chemical pollutants that are known or suspected to cause cancer or other serious health effects, such as reproductive problems or birth defects, and that adversely affect the environment.

These regulations will require coal-fired power plants that have not yet installed pollution control equipment to do so and, in some cases, will require plants with existing control equipment to improve performance.

Over the last several decades, state and federal clean air rules to address acid rain and ground-level smog led to power plant owners successfully deploying a range of advanced pollution control systems at hundreds of facilities across the country, providing valuable experience with the installation and operation of these technologies. In addition, many states adopted mercury reduction requirements in the absence of federal rules, leading to new controls and significant reductions of this air toxic from a number of coal power plants over the past several years. This has provided industry with a working knowledge of a suite of air pollution control devices and techniques that can comply with EPA's proposed Transport Rule and Air Toxics Rule.

This report provides an overview of well-established, commercially available emission control technologies for SO_2 and NOx, and HAPs, such as mercury, chromium, lead and arsenic; acid gases, such as hydrogen chloride and hydrogen fluoride; dioxins and furans; and other toxic air emissions.

The key findings of the report include:

- **The electric power sector has a range of available technology options as well as experience in their installation and operation that will enable the sector to comply with the Transport Rule and the Air Toxics Rule.**
    - The electric power sector has long and successful experience installing many of the required pollution control systems.

  - The first flue gas desulfurization (scrubber) system was installed in 1968 and more than 40 years later, the plant is still in operation and undergoing a performance upgrade.
  - To reduce SO_2 emissions, about 60 percent of the nation's coal fleet has already installed scrubber controls, the most capital intensive of the pollution control systems used by coal-fired power plants.
  - About half of the nation's coal fleet has already installed advanced post-combustion NOx controls, with the first large-scale coal-fired selective catalytic reduction (SCR) system on a new boiler in the U.S. placed in service in 1993 and the first retrofit in the U.S. placed in service in 1995.

- **Modern pollution control systems are capable of dramatically reducing air pollution emissions from coal-fired power plants.**
  - Although scrubbers installed in the 1970s and 1980s typically obtained 80-90 percent SO_2 removal, innovation has led to modern systems now capable of achieving 98 percent or greater removal.
  - SCR can achieve greater than 90 percent NOx removal.
  - Coal-fired power plants, equipped with baghouse systems, report greater than 90 percent removal of mercury and other heavy metals.

- **Pollution controls that significantly reduce mercury emissions from coal-fired power plants have already been installed, demonstrated, and in operation at a significant number of facilities in the United States. This experience demonstrates the feasibility of achieving the mercury emissions limits in the proposed Air Toxics Rule.**
  - In 2001, under cooperative agreements with the Department of Energy, several coal plant operators started full-scale testing of activated carbon injection (ACI) systems for mercury control.
  - Since 2003, many states have led the way on mercury control regulations by enacting statewide mercury limits for coal power plants that require mercury capture rates ranging from 80 to 95 percent. Power plants in a number of these states have already installed and are now successfully operating mercury controls that provide the level of mercury reductions sought in EPA's proposed Air Toxics Rule.
  - At present, about 25 units representing approximately 7,500 MW are using commercial technologies for mercury control. In addition, the Institute of Clean Air Companies (ICAC), a national association of companies providing pollution control systems for power plants and other stationary sources, has reported about 55,000 MW of new bookings.

- ➢ **A wide variety of pollution control technology solutions are available to cost-effectively control air pollution emissions from coal-fired power plants, and many technologies can reduce more than one type of pollutant.**

- o A variety of pollution control solutions are available for different plant configurations.

  - o The air pollutants targeted by the Transport Rule and the Air Toxics Rule are captured to some degree by existing air pollution controls, and, in many cases, technologies to control one pollutant have the co-benefit of also controlling other pollutants. For example, scrubbers, which are designed to control SO_2, are also effective at controlling particulate matter, mercury, and hydrogen chloride.

  - o Dry sorbent injection (DSI) has emerged as a potential control option for smaller, coal-fired generating units seeking to cost-effectively control SO_2 and acid gas emissions.

  - o As highlighted below in Table ES-1, because of these "co-benefits," in many cases it may not be necessary to add separate control technologies for some pollutants.

Table ES-1. Control Technology Emission Reduction Effect

	SO_2	NOx	Mercury (Hg)	HCl	PM	Dioxins/ Furans
Combustion Controls	N	Y	C	N	N	Y
SNCR	N	Y	N	N	N	N
SCR	N	Y	C	N	N	C
Particulate Matter Controls	N	N	C	N	Y	C
Low Sulfur Fuel	Y	C	N	C	N	N
Wet Scrubber	Y	N	C	Y	C	N
Dry Scrubber	Y	N	C	Y	C*	N
DSI	Y	C	C	Y	N	C
ACI	N	N	Y	N	N	Y

N = Technology has little or no emission reduction effect
Y = Technology reduces emissions
C = Technology is normally used for other pollutants, but has a co-benefit emission reduction effect
* When used in combination with a downstream particulate matter control device, such as a baghouse

- ➢ **The electric power sector has a demonstrated ability to install a substantial number of controls in a short period of time, and therefore should be able to comply with the timelines of the proposed EPA air rules.**

  - o Between 2001 and 2005, the electric industry successfully installed more than 96 gigawatts (GW) of SCR systems in response to NOx requirements.

  - o In response to the Clean Air Interstate Rule (CAIR), about 60 GW of scrubbers and an additional 20 GW of SCR were brought on line from 2008 through 2010. Notably, most companies were "early movers," initiating the installation process before EPA finalized its rules.

  - Available technologies that are less resource and time-intensive will provide additional compliance flexibility. For example, DSI and dry scrubbing technology design and installation times are approximately 12 and 24 months, respectively.

- **The electric power sector has access to a skilled workforce to install these proven control technologies.**

- In November 2010, ICAC sent a letter to U.S. Senator Thomas Carper confirming the nation's air pollution control equipment companies repeatedly have successfully met more stringent NOx, SO_2 and mercury emission limits with timely installations of effective controls and are well prepared to meet new EPA requirements.

  - Also in November 2010, the Building and Construction Division of the AFL-CIO sent a letter to Senator Carper indicating that "[t]here is no evidence to suggest that the availability of skilled manpower will constrain pollution control technology development."

  - Actual installation of pollution control equipment far exceeded EPA's earlier estimate of industry capability that it made during the Clean Air Interstate Rule (CAIR) rulemaking.

  - In response to CAIR, boilermakers increased their membership by 35 percent in only two years (between 1999 and 2001) to meet peak labor demand.

In summary, a range of available and proven pollution control technologies exists to meet the requirements of EPA's proposed Transport Rule and Air Toxics Rule. In many cases, these technologies, some of which have been operating for decades, have a long track record of effective performance at many coal-fired power plants in the U.S.

The electric power sector has shown that it is capable of planning for and installing pollution controls on a large portion of the nation's fossil fuel generating capacity in a relatively short period of time. Suppliers have demonstrated the ability to provide pollution control equipment in a timely manner, and the skilled labor needed to install it should be available to meet the challenge as well. Examples of successful pollution control retrofits are provided throughout this report.

Introduction

The U.S. Environmental Protection Agency (EPA) is currently developing two major air quality rules under the Clean Air Act ("CAA" or "the Act") to reduce air pollution from power plants: (1) the Transport Rule, and (2) the Air Toxics Rule. These regulations will require certain power plants that have not installed pollution control equipment to do so and others to improve their performance. The discussion that follows provides an overview of these regulations, including a discussion of the sources regulated by the rules and the air pollutants the rules address. Both rules are being developed in response to court decisions overturning prior EPA regulatory programs and have long been anticipated by the electric power sector.

Transport Rule

The Transport Rule—proposed by EPA in July 2010—is designed to reduce the interstate transport of harmful air pollution from power plants in the eastern U.S. as required by the CAA. The "good neighbor" provisions of the Act require states to prohibit air pollution emissions that "contribute significantly" to a downwind state's air quality problems.[1] For example, EPA found that power plants in West Virginia significantly affect the air quality status of counties in Ohio, Indiana, Pennsylvania, Kentucky, and Michigan—hindering these states from achieving or maintaining federal air quality standards.[2]

In keeping with the purpose of the "good neighbor" provisions in the Act, the Transport Rule will assist states and cities across the eastern U.S. in complying with the national, health-based fine particulate, or $PM_{2.5}$, and 8-hour ozone standards by limiting SO_2 and NOx emissions from power plants in the region. Fine particulates can be inhaled deep into the lungs, and have been linked to increased hospital admissions and emergency room visits for various respiratory or cardiovascular diseases, respiratory illness and symptoms, lung function changes, and increased risk of premature death. Ground-level ozone is a respiratory irritant that adversely affects both people with respiratory disease and healthy children and adults. Exposure to ozone through inhalation can result in reduced lung function and inflamed airways, aggravating asthma or other lung diseases. As with fine particulate matter, ozone exposure is also linked to increased risk of premature death.

The Transport Rule will replace the earlier Clean Air Interstate Rule (CAIR) that EPA had issued in March 2005.[3] Under CAIR, EPA limited NOx and SO_2 emissions from 28 states and the District of Columbia, and directed each state to file a plan for meeting those limits, or emission caps. In July 2008, however, the U.S. Court of Appeals for the District of Columbia Circuit struck down CAIR after finding several flaws in the rule.[4] In a subsequent ruling, the court determined that CAIR could remain in place until EPA developed a replacement program.[5]

Table 1. The Clean Air Transport Rule

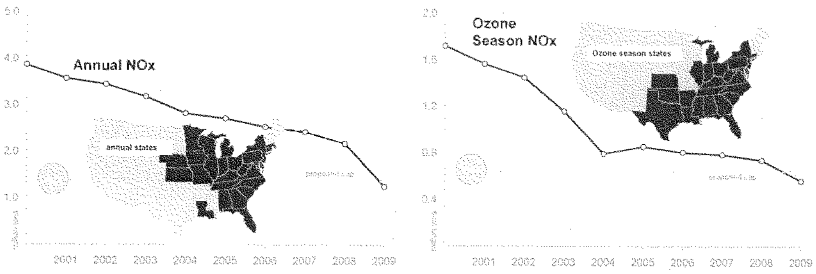
Regulated Pollutants	Affected Sources	Compliance Dates	Regulatory Mechanism
Sulfur dioxide (SO_2) Nitrogen oxides (NOx)	Fossil fuel-fired power plants 25 MW and larger in 31 eastern states and DC	Phase 1: 2012 Phase 2: 2014	EPA's preferred approach would allow intrastate trading among covered power plants with some limited interstate trading

EPA's proposed emissions caps for SO_2 and NOx are summarized in the following figures. EPA notes in the proposed rule that additional ozone season (May 1 to September 30) NOx reductions will likely be needed to attain the national ozone standards.[6] Therefore, the agency plans to propose a new transport rule in 2011, to become final in 2012, to reflect the revised National Ambient Air Quality Standards (NAAQS) for ozone when they are promulgated. While the Transport Rule only proposes to require reductions from the power sector, EPA notes, "it is possible that reductions from other source categories could be needed to address interstate transport requirements related to any new NAAQS."[7]

EPA estimates that the proposed rule would yield $120 billion to $290 billion in annual health and welfare benefits in 2014,[8] which exceed the estimated $2.8 billion in annual costs that EPA estimates power plants will incur to comply with the rule by a factor of more than 30.[9] To meet the new requirements, EPA expects plants will employ a wide range of strategies, including operating already

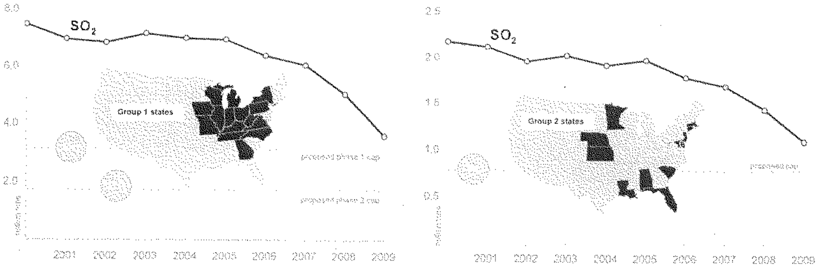
Clean Air Transport Rule: Proposed NOx Emissions Caps

EPA's proposed Transport Rule would establish two NOx programs: (1) an annual NOx program, and (2) an ozone season (summer time) NOx program (see map below). Annual NOx emissions would be capped at 1.4 million tons per year beginning in 2012. The 2012 cap represents a 10 percent increase over 2009 emissions levels. Ozone season NOx emissions would be capped at 0.6 million tons beginning in 2012. The ozone season cap represents a 15 percent increase over 2009 emissions levels.



Clean Air Transport Rule: Proposed SO_2 Emissions Caps

EPA's proposed Transport Rule would establish two independent trading programs for SO_2: (1) group 1 states; and (2) group 2 states (see maps below). SO_2 emissions from group 1 states would be capped at 3.1 million tons per year beginning in 2012 and 1.7 million tons per year beginning in 2014. The 2012 cap represents a 13 percent reduction below 2009 emissions levels. SO_2 emissions from group 2 states would be capped at 0.8 million tons beginning in 2012. The 2012 cap for group 2 states represents a 29 percent reduction below 2009 emissions levels.



installed pollution control equipment more frequently, using low sulfur coal, or installing new control equipment.

Air Toxics Rule

The U.S. EPA's proposed Air Toxics Rule will establish, for the first time, federal limits on hazardous air pollutant (HAP) emissions from coal- and oil-fired power plants. The HAPs covered include mercury, lead, arsenic, hydrogen chloride, hydrogen fluoride, dioxins/furans, and other toxic substances identified by Congress in the 1990 amendments of the CAA. The rule establishes "maximum achievable control technology" (MACT) limits for many of these.

The U.S. EPA's prior effort to regulate HAP emissions from power plants was overturned by court challenges. On February 8, 2008, a federal court held that EPA violated the CAA when it sought to regulate mercury-emitting power plants through the Clean Air Mercury Rule (CAMR), an interstate cap-and-trade program issued by EPA in March 2005.[10] The court concluded that EPA violated the CAA by failing to make a specific health-based finding to remove electric generating units from regulation under CAA section 112.[a]

On March 16, 2011, EPA proposed its replacement for CAMR that would establish numerical MACT emission limits for existing and new coal-fired electric power plants that would cover mercury, particulate matter (as the surrogate for non-mercury toxic metals), and hydrogen chloride (as the surrogate for toxic acid gases). The proposed rule would also establish work practice standards for organic air toxics (e.g., dioxins and furans).[11] EPA projects the proposed rule will reduce mercury emissions from covered power plants by 91 percent, acid gas emissions by 91 percent, and SO_2 emissions by 55 percent.[12] The projected mercury reductions are in the range of what a number of states already require for coal-fired power plants.[13] A consent decree with public health and environmental groups requires EPA to finalize the standards by November 16, 2011. Table 2 summarizes elements of the proposed Air Toxics Rule.

EPA estimates that the Air Toxics Rule would yield $140 billion in annual health and welfare benefits in 2016.[14] The estimated annual cost of the program is $10.9 billion.[15] EPA emphasizes that the proposed rule would cut emissions of pollutants that are of particular concern for children. Mercury and lead can adversely affect developing brains–including effects on IQ, learning, and memory.

Table 2. The Air Toxics Rule

Regulated Pollutants	Affected Sources	Compliance Dates	Regulatory Mechanism
Mercury Non-mercury metals, such as arsenic, chromium, cadmium, and nickel Organic HAPs (e.g., dioxins/furans) Acid gases (HCl, HF)	Coal- and oil-fired power plants 25 MW and larger	Early 2015 **Note:** EPA can grant a one year extension for a source to install controls	Numerical emission limits for mercury, other toxic metals, and acid gases; work practice standards for organic air toxics (e.g., dioxins/furans)

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[a] *"EPA's removal of these [electric generating units] from the section 112 list violates the CAA because section 112(c)(9) requires EPA to make specific findings before removing a source listed under section 112; EPA concedes it never made such findings. Because coal-fired [electric generating units] are listed sources under section 112, regulation of existing coal-fired [electric generating units'] mercury emissions under section 111 is prohibited, effectively invalidating CAMR's regulatory approach." New Jersey v. EPA, 517 F.3d 574 (D.C. Cir. 2008).*

Overview of Air Pollution Control Technologies

There are a wide range of technologies available for controlling air pollution emissions from coal-fired power plants. The most appropriate combination of control technologies will vary from plant-to-plant depending on the type and size of the electric generating unit, age, fuel characteristics, and the boiler design.

Many of the air pollutants targeted by the proposed Transport Rule and the Air Toxics Rule are captured to some degree by existing air pollution control devices. Table 3 summarizes the various pollutants and the technologies that are currently being applied or may be applied in the future to control them. In many cases, technologies designed to control one pollutant will also control others. These "co-benefits" may or may not be adequate to achieve compliance with the Transport Rule or the Air Toxics Rule. As a result, in some cases, it may be necessary to add separate control technologies for some pollutants.

Table 3. Control Technology Emission Reduction Effect

	SO_2	NOx	Mercury (Hg)	HCl	PM	Dioxins/ Furans
Combustion Controls	N	Y	C	N	N	Y
Selective Non-Catalytic Reduction (SNCR)	N	Y	N	N	N	N
Selective Catalytic Reduction (SCR)	N	Y	C	N	N	C
Particulate Matter Controls (i.e., ESP or baghouse)	N	N	C	N	Y	C
Lower Sulfur Fuel	Y	C	N	C	N	N
Dry Scrubber	Y	N	C	Y	C*	N
Wet Scrubber	Y	N	C	Y	C	N
Dry Sorbent Injection (DSI)	Y	C	C	Y	N	C
Activated Carbon Injection (ACI)	N	N	Y	N	N	Y

N = Technology has little or no emission reduction effect
Y = Technology reduces emissions
C = Technology is normally used for other pollutants, but has a co-benefit emission reduction effect
* When used in combination with a downstream particulate matter control device, such as a baghouse

Methods for Controlling SO_2 Emissions

SO_2 is a highly reactive gas linked to a number of adverse effects on the human respiratory system. In 2008, power plants accounted for 66 percent of the national SO_2 emissions inventory,[16] with the vast majority of this contribution (more than 98 percent) coming from coal-fired power plants.[17]

There are two basic options for controlling SO_2 emissions from coal-fired power plants, which is formed from the oxidation of sulfur in the fuel: (1) switching to lower sulfur fuels; and (2) SO_2 capture, including Flue Gas Desulfurization (FGD), or more commonly referred to as "scrubbing." Table 4 shows the various methods for controlling SO_2 emissions. These methods include those that have been widely used on power plants, such as low sulfur coal and scrubbing, as well as less costly technologies that may be more attractive for smaller boilers, such as dry sorbent injection (DSI).

Table 4. SO_2 Emissions Control Methods

Methods of Control	
Lower Sulfur Fuel	Method – Lower sulfur fuel reduces SO_2 formation Reagent – None Typical fuel types – Powder River Basin coal and lower sulfur bituminous coal Capital Cost – Low Co-benefits – May reduce NOx, HCl, and HF emissions
Dry Sorbent Injection	Method – Dry Sorbent Injection captures SO_2 at moderate rates, downstream PM control device captures dry product Reagent – Trona, sodium bicarbonate, hydrated lime Typical Fuel Types – Most often solid fuels (i.e., coals – lignite, sub-bituminous, bituminous) Capital Costs- Low to moderate Co-benefits – NOx and HCl and HF reduction, Hg reduction, removal of chlorine, a precursor to dioxins/furans
Dry Scrubber with Fabric Filter	Method – Reagent + water react to capture acid gases and dry product captured in downstream fabric filter Reagent – Hydrated lime Typical Fuel Types – Coal Capital Costs – High Co-benefits – High SO_2 and Hg capture (esp. bituminous coals), high PM and HCl capture
Wet Scrubber	Method – Reagent + water react to capture acid gases Reagent – Limestone, lime, caustic soda Typical Fuel Types – Coal, petroleum coke, high sulfur fuel oil Capital Costs – High Co-benefits –Highest SO_2 capture, high oxidized Hg and high HCl capture, PM capture
Wet Scrubber Upgrades	Method – Upgrade older scrubbers to provide performance approaching those of new scrubbers Reagent – Limestone, lime, etc. Typical Fuel Types – Coal, petroleum coke, high sulfur fuel oil Capital Costs – Low to moderate Co-benefits – Same as wet scrubber
Co-benefit Methods of Control	
None	SO_2 is a key pollutant that often is the major driver in emission control technology selection

Lower Sulfur Coal

Changing to lower sulfur coal was the most widely used approach for compliance with the Acid Rain Program (Title IV of the 1990 Clean Air Act Amendments). Certain coal types are naturally low in sulfur, such as sub-bituminous coal mined in the Powder River Basin (PRB) of Montana and Wyoming.[b]

Some facilities cannot burn 100 percent PRB coal without substantial modifications to the boiler or fuel handling systems. These facilities can blend PRB or another lower sulfur coal with a bituminous coal to reduce emissions. Facilities that are not able to burn lower sulfur coals or facilities needing greater SO_2 emissions reductions may need some form of flue gas treatment.

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[b] Coal is classified into four general categories, or "ranks." They range from lignite through sub-bituminous and bituminous to anthracite. Sub-bituminous and bituminous coals are the most widely used coal types, and the SO_2 emissions from burning these fuels can vary by a factor of 10 or more, depending upon the fuel sulfur content and the heating value of the fuel. Lignite fuels have low heating values, making them uneconomical to transport, and are generally limited in use to mine-mouth plants. Anthracite coal is used in very few power plants.

Co-benefits of low sulfur coal – PRB coal is relatively low in nitrogen, which results in lower NOx emissions. It is also very low in chlorine, so hydrogen chloride (HCl) emissions are low for PRB coal.

Flue Gas Desulfurization (FGD) or "Scrubbing"

As EPA and states have further limited SO_2 emissions, an increasing number of coal-fired power plants have installed FGD systems. FGD controls enable a plant operator to use a wider variety of coals while maintaining low SO_2 emissions. There are two basic forms of FGD – wet and dry. As shown in Table 5, nearly two-thirds of the coal-fired power plant capacity in the United States is scrubbed or is projected to be scrubbed in the near future. Most plant operators have opted for wet FGD systems, particularly on larger coal-fired power plants. In response to the Clean Air Interstate Rule, coal-fired power plants added about 60 gigawatts (GW) of scrubbers in the three year period from 2008 through 2010.[18]

Table 5. Coal-Fired Power Plant Scrubbers[19]

Scrubber Type	Sum of Capacity (%)	# Boilers	Average Capacity (MW)
FGD (wet)	170 GW (52%)	371	457
FGD (dry)	22 GW (7%)	114	196
Total Scrubbed	**192 GW (59%)**	**485**	**396**
No scrubber	134 GW (41%)	788	171
Total	**326 GW**	**1,273**	**256**

Wet Scrubbers

Wet scrubbers are capable of high rates of SO_2 removal. In a wet FGD system, a lime or limestone slurry reacts with the SO_2 in the flue gas within a large absorber vessel to capture the SO_2, as shown in Figure 1.[20] Wet FGD systems may use lime or limestone. Lime is more reactive and offers the potential for higher reductions with somewhat lower capital cost; however, lime is also the more expensive reagent. As a result, limestone-forced oxidation (LSFO) wet scrubber technology is the most widely used form of wet FGD and is more widely used on coal-fired power plants than every other form of FGD combined. State-of-the-art LSFO systems are capable of providing very high levels of SO_2 removal – on the order of 98 percent or more.

The first wet scrubber system in the U.S. was designed by Black & Veatch and installed in 1968 at the Lawrence Energy Center in Kansas. More than 40 years later, the system is still in operation, and the facility is undertaking a major upgrade to improve the system's performance. The facility is also adding a pulse jet fabric filter.[21]

In the absorber, the gas is cooled to below the saturation temperature, resulting in a wet gas and high rates of capture. Modern wet scrubbers typically have SO_2 removal rates of over 95 percent and can be in the range of 98 percent to 99 percent.[22] The reacted

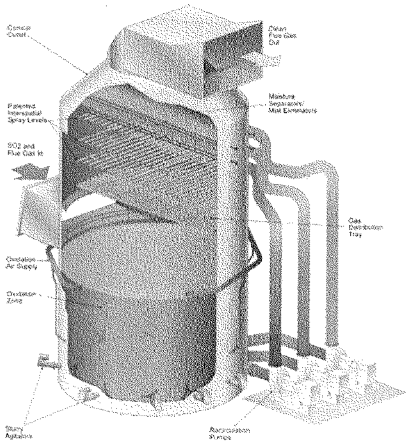


Figure 1. Wet Flue Gas Desulfurization
Image courtesy of Babcock and Wilcox Company

limestone and SO_2 form a gypsum by-product that is often sold for the manufacturing of wallboard.

Because a wet FGD system operates at low temperatures, it is usually the last pollution control device before the stack. The wet FGD absorber is typically located downstream of the PM control device (most often an electrostatic precipitator though many power plants have baghouses) and immediately upstream of the stack. Wet FGD is frequently used to treat the exhaust gas of multiple boilers with the gases being emitted through a common stack. A single absorber can handle the equivalent of 1,000 megawatts (MW) of flue gas.

Wet scrubber retrofits are capital intensive due to the amount of equipment needed, and recent installations for the Clean Air Interstate Rule have been reported to have an average cost of $390/kW.[23] EPA estimates a capital cost of about $500/kW ($2007) for a wet scrubber (limestone forced oxidation) on a 500 MW coal unit.[24] There can be, however, a significant variation in costs depending upon the size of the unit and the specifics of the site. Generally, smaller boilers (under 300 MW) have been shown to be significantly more expensive to retrofit with wet scrubbers (capital cost normalized to a $/KW basis) than larger boilers due to economies of scale. The economies of scale become less significant as boiler size increases.[25] As a result, wet scrubbers are a less attractive alternative for controlling SO_2 on small units. Companies can sometimes offset the cost of installing wet scrubber technology by switching to less expensive high sulfur coal supplies. Because of the high capital costs of the technology, wet scrubbers are generally only installed on power plants where the owner expects to operate the plant for an extended number of years.

Due to their complexity and the size of the equipment, EPA estimates that the total time needed to complete the design, installation, and testing of a wet FGD system at a typical 500 MW power plant with one FGD unit is 27 months, and longer if multiple boilers or multiple absorbers are necessary. Actual installation times will vary based upon the specifics of the plant, the need to schedule outages with FGD hook up, and other factors.

Co-benefits of wet FGD – FGDs have been shown to be effective at removing other pollutants including particulate matter, mercury, and hydrochloric acid. For this reason, facilities that are equipped with wet or dry FGD systems may avoid the need to install additional controls for hazardous air pollutants.

Dry Scrubbers

Dry scrubber technology (dry FGD) injects hydrated lime and water (either separately or together as a slurry) into a large vessel to react with the SO_2 in the flue gas. Figure 2 shows a schematic of a dry scrubber.

The term "dry" refers to the fact that, although water is added to the flue gas, the amount of water added is only just enough to maintain the gas above the saturation (dew point) temperature. In most cases, the reaction products and any unreacted lime from the dry FGD process are captured in a downstream fabric filter (baghouse), which helps provide additional capture of SO_2. Modern dry FGD systems typically provide SO_2 capture rates of 90 percent or more.

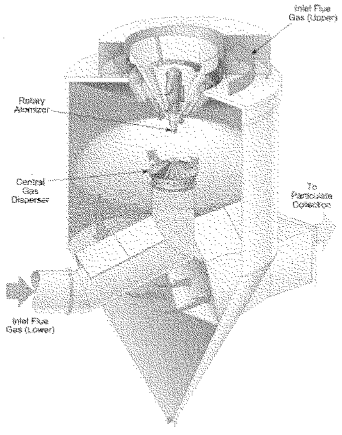


Figure 2. Dry Flue Gas Desulfurization
Image courtesy of Babcock and Wilcox Company

Historically, dry FGDs have been used primarily on low sulfur coals because the reagent, lime, is more expensive than reagents used in wet FGD systems. Also, because the systems are designed to maintain the flue gas temperatures above the dew point, this limits the amount of SO_2 that can be treated by a spray dryer. Another form of dry FGD, circulating dry scrubber systems (CDS), inject the water and lime separately, and have been shown to achieve high SO_2 removal rates in excess of 95 percent on higher sulfur coals. Lime is more costly than limestone, the most commonly used reagent for wet scrubber systems.

Case Study: Dry Scrubber

In Massachusetts, First Light's Mt. Tom Power Plant, a 146 MW coal-fired unit that went into service in 1960, installed state-of-the-art pollution control equipment in 2009 to meet state and federal environmental regulations. In December 2009, the plant installed a circulating dry scrubber to reduce SO_2 and mercury emissions during a routine outage. A precipitator and baghouse were also installed to remove particulate matter emissions. Total project costs were $55 million, or $377/kW. The project has reduced the plant's SO_2 emissions by approximately 70 percent, with the plant's 2009 SO_2 emission rate of 0.73 lbs SO_2/mmBtu dropping to 0.22 lbs SO_2/mmBtu in 2010.

Source: U.S. Environmental Protection Agency, Clean Air Markets-Data and Maps; http://camddataandmaps.epa.gov/gdm/index.cfm?fuseaction=emissions.wizard (accessed March 17, 2011).

Dry FGD systems tend to be less expensive than wet FGD systems because they are less complex and generally smaller in size. They also use less water. The lower reagent cost of wet FGD and the ability to burn lower cost, higher sulfur coals make wet FGD more attractive for large facilities. EPA estimates a capital cost of about $420/kW ($2007) for a dry scrubber (lime spray dryer) on a 500 MW coal unit.[26] The Turbosorp system installed at the AES Greenidge plant in New York cost $229/KW ($2005).[27] Depending upon the specifics of the facility to be retrofit, the cost could be higher in some cases.

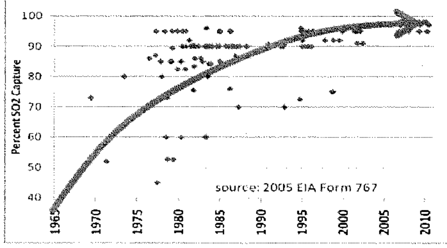
Dry FGD systems are less complex and generally require less time to design and install than wet FGD systems. The Institute to Clean Air Companies (ICAC) estimates that dry scrubbers can be installed in a time frame of 24 months.[28]

Co-benefits of Dry FGD – Dry FGD pollutant co-benefits include greatly enhanced capture of hazardous air pollutants, especially PM, mercury and HCl (as discussed later in the report).

Upgrades to Existing Wet FGD Systems

Modern wet FGD systems are capable of SO_2 removal rates in the range of 98 percent or more. Limestone wet scrubber removal efficiencies have improved dramatically since the 1970s as shown in Figure 3.[29] As a result, there are opportunities to improve scrubber performance from many existing scrubbers that were built in the 1970s and 1980s. An advantage of this approach is that substantial SO_2 reductions are possible at a far lower cost than installing a new scrubber and in a much shorter period of time. Each scrubber upgrade is unique, so cost and schedule will vary. Depending upon the scope of a scrubber upgrade, a scrubber upgrade could be implemented in under a year as opposed to three to four years for a new scrubber installation. All key areas of many older FGD systems (absorber, reagent preparation, and dewatering) can benefit from modern upgrades. Because each system is unique, an effective FGD system-wide upgrade process is most successful after an extensive system review and diagnostics.

There have been numerous examples of FGD upgrades over the last several years that have improved SO_2 removal efficiencies. For example, the Fayette Station Unit 3, a 470 MW tangentially-fired coal unit in Texas, completed an upgrade to its 1988-vintage scrubber in 2010. The plant's control efficiency was increased from about 84 percent to 99 percent, higher than the guaranteed SO_2 removal efficiency of 95.5 percent.[30] In Kentucky, E.On's Trimble County Generating Station Unit 1, a 550 MW tangentially-fired coal boiler, completed a scrubber upgrade in 2006. Its scrubber, installed in the 1980s, was originally designed for 90 percent removal efficiency. The scrubber system is now able to achieve over 99 percent SO_2 removal efficiency.[31] In Indiana, NiSource upgraded the scrubbers at Schahfer Units 17 and 18 in 2009.[32] The scrubber upgrades increased SO_2 removal efficiency from 91 percent to 97 percent.[33]



source: 2005 EIA Form 767

Figure 3. Historical Trends in Limestone Wet Scrubber SO_2 Removal Efficiency of Limestone Wet Scrubbing Systems

Dry Sorbent Injection (DSI)

DSI is the injection of dry sorbent reagents that react with SO_2 and other acid gases, with a downstream PM control device to capture the reaction products.

The most common DSI reagent in use is Trona, a naturally occurring mixture of sodium carbonate and sodium bicarbonate mined in some western states. Other reagents have also been used, such as sodium bicarbonate and hydrated lime. Sodium bicarbonate is capable of higher SO_2 removal efficiencies than Trona because it is more reactive. Trona can achieve varying levels of SO_2 reductions, from a range of 30-60 percent when injected upstream of an ESP, or up to 90 percent when injected upstream of a fabric filter. Fabric filters allow greater contact between the gas and the injected sorbent than ESPs, enabling better removal for any given reagent treatment rate. The level of removal will vary depending upon the circumstances of the facility and the injection system.

DSI equipment is relatively simple and inexpensive when compared to a scrubber and can be installed typically within 12 months.[34] Unlike scrubbers that require additional reaction chambers to be installed, in DSI the reaction occurs in the existing ductwork and air pollution control equipment. The basic injection system with storage silo costs around \$20/kW; however, in some cases additional storage and material handling may be necessary that will add cost. But, even with the additional equipment, the capital cost of a DSI system will be substantially less than that of a full wet or dry scrubber, which can cost as high as \$400/kW. Reagents used in DSI are more costly than those used in wet or dry scrubbers, and the reagent is not as efficiently utilized, which can contribute to a higher cost of control in terms of dollars per ton of SO_2 reduced.

Case Study: Dry Sorbent Injection

Conectiv Energy installed a DSI Trona system at Edge Moor Units 3-4 to comply with Delaware's multi-pollutant emissions control rule. The project was several years in planning and operated from 2009 to mid-2010. The emission rates went from 1.2 lbs SO_2/mmBtu to 0.37 lbs SO_2/mmBtu with the use of Trona. Since the purchase of the facility by Calpine in mid-2010, coal is no longer burned thus eliminating the need for the Trona system. In New York, NRG installed a Trona system at its Dunkirk (530 MW) and Huntley stations (380 MW). This project is the first of its kind in the U.S. in which Trona and powder-activated carbon (PAC) are simultaneously injected into the flue gases to control both SO_2 and mercury emissions. The DSI system included several Trona storage and injection systems with equipment buildings, 6000 feet of transport piping, Trona railcar unloading and transfer systems, and associated bulk storage silos. Performance tests indicate that emissions of SO_2 have been reduced by over 55 percent, mercury levels have been reduced by over 90 percent, and particulate levels have been reduced to less than 0.010 lbs/mmBtu.

Source: Pietro, J. and Streit, G. (NRG Energy). "NRG Dunkirk and Huntley Environmental Retrofit Project." Presented to Air & Waste Management Association – Niagara Frontier Section, September 23, 2010.

Co-benefits of DSI – DSI has been shown to be very effective in the capture of the acid gases, HCl and HF. DSI has been shown to enhance mercury capture for facilities that burn bituminous coal by removing sulfur trioxide (SO_3) that is detrimental to mercury capture through ACI. In the case of PRB coals, the impact on mercury capture might be negative. Injection of Trona or sodium bicarbonate can also remove NOx in the range of 10-20 percent, although NOx removal is generally not a principal objective of DSI.[35] If DSI is installed at a point in the gas stream that is upstream of the dioxins/furans formation temperature, it is expected to remove the precursor chlorine that leads to their production.

Methods for Controlling NOx Emissions

Nitrogen oxides (NOx) are an acid rain precursor and a contributor to the formation of ground-level ozone, which is a major component of smog. In 2008, power plants accounted for 18 percent of the national NOx emissions inventory. Most of the NOx formed during the combustion process is the result of two oxidation mechanisms: (1) reaction of nitrogen in the combustion air with excess oxygen at elevated temperatures, referred to as thermal NOx; and (2) oxidation of nitrogen that is chemically bound in the coal, referred to as fuel NOx. Controlling NOx emissions is achieved by controlling the formation of NOx through combustion controls or by reducing NOx after it has formed through post-combustion controls. Table 6 summarizes key NOx control technologies.

Table 6. NOx Emissions Control Methods

Methods of Control	
Combustion Controls	Method – Reduce NOx formation in the combustion process itself for levels of reduction that vary by application Reagent – None Typical fuel types – All fuels Capital Cost – Low to moderate Co-benefits – Potential impacts on Hg, CO and precursors of dioxins/furans
Selective Non-Catalytic Reduction	Method – Reagent injected into furnace reacts with and reduces NOx at moderate removal rates of about 30% Regent – Urea or ammonia Typical Fuel Types – Most often solid or liquid fuels Capital Costs- Low Co-benefits - None
Selective Catalytic Reduction	Method – Reagent reacts with NOx across catalyst bed and reduces NOx at high rates of about 90% Reagent – Ammonia (or urea that is converted to ammonia) Typical Fuel Types – Any fuel Capital Costs – High Co-benefits – Oxidation of Hg for easier downstream capture in a wet scrubber, reduction of dioxins/furans
Co-benefit Methods of Control	
Low Sulfur Coal	Conversion to PRB coal for SO_2 reduction will also reduce NOx due to lower fuel nitrogen in PRB coal
Dry Sorbent Injection	DSI with Trona can provide NOx reduction of about 10-15%

Combustion Controls

Combustion controls minimize the formation of NOx within the furnace and are frequently the first choice for NOx control because they are usually lower in cost than post-combustion controls. For most forms of combustion control, once installed there is little ongoing cost because there are no reagents or catalysts to purchase. Combustion controls reside within the furnace itself, not in the exhaust gas stream, and include such methods as low NOx burners (LNB), over-fire air (OFA), and separated over-fire air (SOFA). Reburning technology is another combustion control option, but it chemically reduces NOx formed in the primary combustion zone. Reburning technology may also utilize natural gas.

Most utilities have already achieved substantial reductions in NOx emissions from implementation of combustion controls, sometimes in combination with post-combustion controls. There are some facilities that can still benefit from combustion controls, but these are generally the smaller units where utilities have not yet invested in NOx controls.

The capital cost of these combustion controls will vary; however, the capital cost is generally far less than that of more costly post-combustion control options, such as Selective Catalytic Reduction (SCR). The capital costs of combustion controls could be anywhere from about $10/kW to several times that, but generally fall below $50/kW. Except for gas reburning, there is little or no increase in operating or fuel costs.

Co-benefits of Combustion NOx Controls – Combustion controls may enhance mercury capture at coal-fired power plants because they can increase the level of carbon in the fly ash. While higher carbon in the fly ash is generally viewed negatively because it is the result of incomplete combustion, it does provide a real benefit in enhancing mercury capture. Combustion controls can also have a positive impact on CO emissions and on concentrations of organic precursors to dioxins/furans.

Post-Combustion NOx Controls

There are limits to the level of NOx control that can be achieved with combustion controls alone. Therefore, post-combustion controls are necessary to achieve very low emissions of NOx. Combustion NOx controls and post-combustion NOx controls can, and often are, used in combination. About half of the nation's coal fleet has already installed advanced post-combustion NOx controls (Table 7).

Table 7. Coal-Fired Power Plant Post-Combustion NOx Controls[36]

Control Type	Sum of Capacity (%)	# Boilers	Average Capacity (MW)
SCR	129 GW (40%)	259	499
SNCR	29 GW (9%)	172	166
Total Post-Combustion NOx	**158 GW (49%)**	**431**	**366**
No Post-Combustion NOx	842 GW (51%)	842	198
Total	**324 GW**	**1,273**	**255**

Selective Catalytic Reduction (SCR)

SCR technology, which has been in use at coal-fired power plants for more than 15 years in the United States, is a post-combustion NOx control system that is capable of achieving greater than 90 percent removal efficiency.[37] The first large-scale coal-fired selective catalytic reduction (SCR) system on a new boiler in the U.S. was placed in service in 1993 in New Jersey, and the first retrofit in the U.S. went into service in 1995 at a power plant in New Hampshire.[38] About 130 GW of the total coal-fired generating capacity in the U.S. is now equipped with SCR, and more SCRs are planned for existing units. Between 2001 and 2005, the electric industry installed more than 96 GW of SCR systems in response to the NOx SIP Call. Coal plant operators installed an additional 20 GW of SCR from 2008 through 2010 in response to the Clean Air Interstate Rule.[39]

SCR utilizes ammonia as a reagent that reacts with NOx on the surface of a catalyst. The SCR catalyst reactor is installed at a point where the temperature is in the range of about 600°F-700°F, normally placing it after the economizer and before the air-preheater of the boiler. The SCR catalyst must periodically be replaced. Typically, companies will replace a layer of catalyst every two to three years. Multiple layers of catalysts are used to increase the reaction surface and control efficiency (Figure 4).

SCR system capital costs will vary over a wide range depending upon the difficulty of the retrofit. Some retrofits have been reported to cost under $100/kW, while others have been reported to cost over $200/kW.[40] Operating costs include ammonia reagent, periodic catalyst replacement, parasitic power, and fixed operating costs.

The EPA estimates that the total time needed to complete the design, installation, and testing at a facility with one SCR unit is about 21 months, and longer for plants that have multiple units to be retrofitted with SCR.[41]

Selective Non-Catalytic Reduction (SNCR)

SNCR is another post-combustion NOx control technology. It typically achieves in the range of 25-30 percent NOx reduction on units equipped with low NOx burners. SNCR reduces NOx by reacting urea or ammonia with the NOx at temperatures around 1,800°F-2,000°F. Therefore, the urea or ammonia is injected into the furnace post-combustion zone itself and, like SCR, reduces the NOx to nitrogen and water.

The capital cost of SNCR is typically much less than that of SCR, falling in the range of about $10-$20/KW, or about $4 million or less for a 200 MW plant. The operating cost of SNCR is primarily the cost of the ammonia or urea reagent. SNCR is most commonly applied to smaller boilers. This is partly because the economics of SCR are more challenging for small boilers. Furthermore, when emissions regulations allow averaging or trading of NOx emissions among units under a common cap, installing an SCR on a large boiler allows utilities to over-control the large unit and use less costly technology, such as SNCR or combustion controls, for NOx control on smaller units.

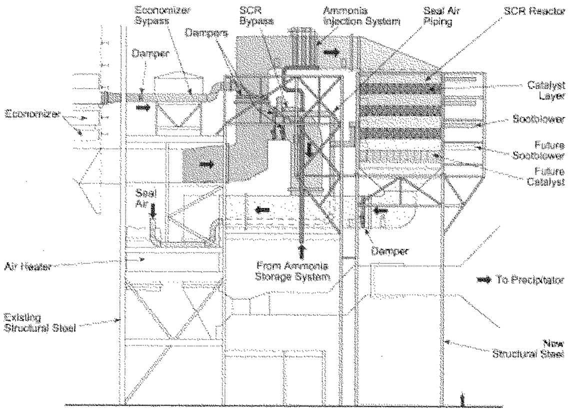


Figure 4. Selective Catalytic Reduction (Retrofit Installation)
Image courtesy of Babcock and Wilcox Company

SNCR systems are relatively simple systems that can be installed in a period of about 12 months.

Hybrid SNCR/SCR

SNCR and SCR may be combined in a "hybrid" manner. In this case, a small layer of catalyst is installed in ductwork downstream of the SNCR system. With the downstream catalyst, the SNCR system can be operated in a manner that provides higher NOx removal rates while using the SCR catalyst to mitigate the undesirable ammonia slip from the SNCR system. Although some NOx reduction occurs across the SCR catalyst, its function is primarily as a means to reduce ammonia slip to an acceptable level. This approach has been demonstrated at the Greenidge power plant in upstate New York, but has not been widely adopted.[42] For some smaller boilers that can accommodate the needed ductwork modifications necessary for "hybrid" SNCR/SCR, this may be an attractive technology for reducing NOx emissions beyond what SNCR is able to achieve.

The hybrid SNCR/SCR system installed at Greenidge was part of a multi-pollutant control system designed to demonstrate a combination of controls that could meet strict emissions standards at smaller coal-fired power plants.[43] The multi-pollutant control system was installed on AES Greenidge Unit 4, a 107 MW, 1953-vintage tangentially-fired boiler. The facility fires high sulfur eastern U.S. bituminous coal. The multi-pollutant control system consists of a hybrid SNCR/SCR technology to control NOx, a circulating fluidized bed dry scrubbing technology to control SO_2, mercury, SO_3, hydrogen chloride, and particulate matter, and an activated carbon injection system to control mercury emissions. Total capital cost of the system was \$349/kW (2005\$), about 40 percent less than the estimated cost of full SCR and wet scrubbers—\$114/kW for the hybrid SNCR/SCR system, \$229/kW for the circulating dry scrubber system and \$6/kW for the activated carbon injection system. The plant has achieved 95 percent SO_2 control, 98 percent mercury removal, and 95 percent SO_3 and HCl removal.[44]

Co-benefits of post-combustion NOx controls – SNCR has no known co-benefit effects on other pollutants. SCR, on the other hand, has the co-benefit effect of enhancing oxidation of elemental mercury, especially for bituminous coals. The effect of mercury oxidation is to enhance mercury capture in a downstream wet FGD because the resulting ionic mercury is extremely water soluble. Several field and pilot studies conducted in the U.S. have found increases in oxidized ionic mercury with the use of SCR controls.[45,46,47,48] For example, testing conducted at the Mount Storm coal-fired power plant in West Virginia evaluated the effect of the unit's SCR system on mercury speciation and capture.[49] The facility fires a medium sulfur bituminous coal. The test program found that the presence of an SCR catalyst can significantly affect the mercury speciation profile. Measurements showed that the SCR catalyst improved the mercury oxidation to levels greater than 95 percent, almost all of which was captured by the downstream wet FGD system. In the absence of the SCR catalyst, the extent of oxidation at the inlet of the FGD system was only about 64 percent. This effect, however, is much reduced with PRB coals because halogen content in PRB coals is low. SCR catalyst can also mitigate emissions of dioxins and furans.[50,51]

Methods for Controlling Hazardous Air Pollutant Emissions

HAPs from power plants include mercury, acid gases (HCl and HF), heavy metals (nickel, chromium, arsenic, selenium, cadmium, and others), and organic HAPs (dioxins and furans). Many HAPs emitted by power plants are captured to some degree by existing air pollution control technologies. However, EPA's proposed Air Toxics Rule will establish emissions standards that will require additional controls be installed. For each of these HAPs, the potential methods for capture are discussed below.

Control of Mercury Emissions

Mercury is found within coal, with its concentration varying widely by coal type and even within coal types. The mercury is released during combustion and becomes entrained in a power plant's flue gas in one of three forms; particle-bound mercury, gaseous elemental mercury, and gaseous ionic mercury. Table 8 lists available methods to control mercury emissions for coal units.

Table 8. Mercury Emissions Control Methods

Methods of Control	
Activated Carbon Injection (ACI)	Method – Activated carbon adsorbs gaseous Hg, converting to particle Hg that is captured in downstream PM control device Reagent – Powdered Activated Carbon Typical Fuel Types – Any fuel, but downstream PM control needed Capital Costs – Low Co-benefits – Some capture of dioxins/furans
Halogen Addition	Method – Halogen (bromine) addition to flue gas increases oxidized Hg that is easier to capture in a downstream scrubber or in PM control device Reagent – Halogen containing additive Capital Costs – Negligible Co-benefits – None
Co-benefit Methods of Control	
PM Controls (ESP, FF, multicyclone)	Method – Captures particle-bound mercury
Dry Sorbent Injection	Method – Increases co-benefit and ACI Hg capture by removing SO_3, which suppresses mercury capture
Dry Scrubber with Fabric Filter	Method – Hg captured in downstream fabric filter
Wet Scrubber	Method – Oxidized mercury captured in wet scrubber
NOx Catalyst	Method – Catalyst in SCR increases oxidation of Hg that is more effectively captured in downstream wet scrubber

Activated Carbon Injection (ACI)

Mercury is often captured using injection of powdered activated carbon (activated carbon injection – ACI) and capture of the injected carbon on a downstream PM capture device (ESP or a baghouse). An ACI system is relatively simple and inexpensive, consisting of storage equipment, pneumatic conveying system, and injection hardware ("injection lances"). Under cooperative agreements with the U.S. Department of Energy, several coal plant operators conducted full-scale testing of ACI systems in 2001.[52]

ACI has been used to capture mercury by effectively converting some of the gaseous ionic and elemental mercury to a particle-bound mercury that is captured in a downstream particulate matter control device, such as an ESP or fabric filter. ACI is very effective at removing mercury except if high sulfur coals are used, or if SO_3 is injected for flue gas conditioning for ESPs, or if the facility has a hot-side ESP and no downstream air pollution controls. SO_3 interferes with mercury capture by ACI; however, upstream capture of SO_3 by DSI, if one is in place, should enable ACI to be more effective at capturing mercury. Fortunately, most of the installed capacity of boilers firing high sulfur fuels is scrubbed and may not need ACI.

Since 2003, many states have led the way on mercury control regulations by enacting statewide mercury limits for power plants that require mercury capture rates ranging from 80 to 95 percent.[53] At present, about 25 units representing about 7,500 MW are using commercial ACI technologies for mercury control. In addition, about 55,000 MW of new bookings are reported by the Institute of Clean Air Companies (ICAC), a national association of companies providing pollution control systems for power plants and other stationary sources.[54]

ACI systems cost in the range of $5/kW and can be installed in about 12 months or less, assuming a baghouse is installed. PSEG's Bridgeport Harbor Generating Station completed the construction and installation of a baghouse and ACI system in under 2 years. The final connection of the controls was completed during a six to eight week outage.

Case Study: ACI Controls

In response to a 2006 Minnesota state mercury law, Xcel Energy agreed to install an ACI system on the 900 MW Unit 3 at its Sherburne County plant (Sherco 3). The unit, which burns low sulfur western coal from Montana and Wyoming, already had a dry scrubber operating to reduce SO_2 emissions. Once it has been tuned to the unit's operational specifications, the ACI system is expected to reduce the plant's mercury emissions by about 90 percent. The system was completed in December 2009 for a total capital cost of $3.1 million, or $3.46/kW. Wisconsin Power and Light installed ACI controls at its Edgewater Generating Station. The system was operational in the first quarter of 2008. Edgewater Unit 5 is a 380 MW plant that fires PRB coal and is configured with a cold-side ESP for particulate control. The total installed costs of the Edgewater Unit 5 ACI system was approximately $8/kW, or approximately $3.04 million.

Source: Southern Minnesota Municipal Power Agency. "Sherco 3: Environmental Controls." August 2010, http://www.smmpa.com/upload/Sherco%203%20brochure%202010.pdf (accessed March 17, 2011).

Starns, T., Martin, C., Mooney, J., and Jaeckels, J. "Commercial Operating Experience on an Activated Carbon Injection System, Paper #08-A-170-Mega-AWMA." Power Plant Air Pollutant Control MEGA Symposium. Baltimore, MD. August 25-28, 2008.

Co-benefits of ACI – ACI co-benefits include the reduction of dioxins and furans.

Halogen Addition

For applications where there is inadequate halogen for conversion of elemental mercury to ionic mercury, such as some western coals, the addition of halogen will increase mercury conversion to the ionic form and will permit higher capture efficiency through co-benefit capture or by ACI. Addition of halogen to PRB coals or to activated carbon injected for mercury capture has been shown to make mercury capture from PRB fired boilers with halogen addition generally high.[55]

Co-Benefit Methods for Mercury Capture

Of the three mercury forms previously mentioned, particle-bound mercury is the species more readily captured as a co-benefit in existing emission control devices, such as fabric filters (also called "baghouses") or electrostatic precipitators (ESPs). Ionic mercury has the advantage that it is extremely water soluble and is relatively easy to capture in a wet FGD/scrubber. Ionic mercury is also prone to adsorption onto fly ash or other material, and may thereby become particle-bound mercury that is captured by an ESP or fabric filter. Elemental mercury is less water soluble and less prone to adsorption, thus remains in the vapor phase where it is not typically captured by control devices unless first converted to another form of mercury more readily captured.

Fabric filters generally provide much higher co-benefit mercury capture than ESPs. Bituminous coal-fired boilers with fabric filters can have high rates of mercury capture based on data collected by the U.S. EPA during its Information Collection Request (ICR) supporting the development of the Air Toxics Rule.[56]

Wet scrubbers with SCR controls upstream have been shown to be very effective in removing oxidized (ionic) mercury. Therefore, when a wet scrubber is present, it is beneficial to take measures to increase the oxidation of mercury upstream of the wet scrubber. Catalysts in SCR systems promote oxidation of mercury, and SCR controls upstream of a wet FGD system have been shown to provide high mercury capture in the range of 90 percent when burning bituminous coals.[57] The precise level of oxidation and capture will vary under different conditions. In a study by the Southern Company, five of its plants with SCR and scrubbers captured an average of 87 percent of mercury over a period of several months.[58]

Co-benefit capture rates of mercury in ESPs, fabric filters, scrubbers, or other devices for bituminous coals are generally greater than that for PRB coals. This is because the higher halogen content (e.g., chlorine) found in eastern coals promotes formation of oxidized mercury.[59]

Acid Gas Control Methods

Strong acids, such as hydrogen chloride (HCl) and hydrogen fluoride (HF), result from the inherent halogen content in the coal that is released during combustion to form acids as the flue gas cools. As with mercury content, the concentration of halogens in the coal varies widely by coal type and even within coal types. Chlorine is of greatest concern because it is usually present in higher concentrations than other halogens in U.S. coals. The U.S. EPA's proposed Air Toxics Rule for power plants sets a numerical emission limit for HCl. The HCl limit also functions as a surrogate limit for the other acid gases, which are not given their own individual emission limits under the proposed rule.

Table 9 shows HCl emission control methods for coal boilers. In principle, wet and dry SO_2 scrubbers can be used for the control of HCl and HF on power plant boilers; however, these are not likely to be necessary because lower cost methods exist. For those facilities with wet or dry scrubbers for SO_2 control, these units will likely provide the co-benefit of HCl capture. For those units that are unscrubbed, these will likely be adequately controlled through retrofit with DSI systems, and a fabric filter.

Table 9. HCl Emissions Control Methods

Methods of Control	
Dry Sorbent Injection	Method – Dry sorbent captures HCl, downstream PM control device captures dry product Regent – Trona, sodium bicarbonate, hydrated lime Typical Fuel Types – Most often solid fuels with PM control Capital Costs – Low to moderate Co-benefits – NOx and SO_2 reduction, Hg reduction, removal of chlorine precursor leading to lower dioxins/furans formation
Dry Scrubber with fabric filter	Method – Reagent + water react to capture acid gas and dry product captured in downstream fabric filter Reagent – Hydrated lime Typical Fuel Types – Solid fuels Capital Costs – High Co-benefits – High Hg capture (esp. bituminous coal), high SO_2 capture, high PM capture
Wet Scrubber	Method – Reagent + water react to capture acid gas Reagent – Limestone, lime, caustic soda Typical Fuel Types – Solid fuels Capital Costs – High Co-benefits – Highest SO_2 capture, high oxidized Hg capture, some PM capture
Co-benefit Methods of Control	
Wet or Dry Scrubbers	Method – SO_2 scrubber has high HCl removal efficiency
Coal Change	Low sulfur PRB coal is also low in chlorine content

Dry Sorbent Injection

Data from DSI commercial projects or pilot testing has indicated that acid gases can be very effectively captured by DSI using Trona, sodium bicarbonate, or hydrated lime. Although DSI is a technology that has not yet seen the wide deployment of other technologies for acid gas controls, like wet or dry scrubbers, data suggest that DSI is an effective technology for controlling emissions of acid gases, including HCl and HF. For example, as shown in Table 10, HCl capture rates of 98 percent have been measured at Mirant's Potomac River station with sorbent injection upstream of the air preheater.[60] Testing of DSI systems has shown that HCl capture is consistently well above the SO_2 capture rate, and that capture rate of HCl on an ESP was in the mid to upper 90 percent range with SO_2 capture in the 60 percent range. With fabric filters, similar HCl capture efficiencies are possible but at lower sorbent treatment rates.[61] Hydrated lime has also been shown in pilot tests to potentially achieve substantial HCl removal at low capital cost.[62]

Table 10. HCl and HF Capture at Mirant Potomac River Station

	Trona Injection	**Sodium Bicarbonate Injection**
HCl (%)	98.8	97.8
HF (%)	78.4	88.0

DSI may be sufficiently effective in removing acid gases in combination with the existing PM control device. In some cases, however, it may be necessary to modify the existing PM control device or to install a new PM control device. If a fabric filter is installed for PM control, this will also facilitate capture of acid gases with DSI, and mercury and dioxins/furans with ACI. Such an approach will be far less expensive than installing a wet scrubber. As indicated above, DSI equipment is relatively simple and inexpensive when compared to a scrubber and can be installed typically within 12 months.

PM Emissions Control

Toxic metals other than mercury are normally in the particle form and are therefore controlled through particulate matter controls, such as ESPs and fabric filters. The proposed Air Toxics Rule for power plants sets numerical PM emission limits as a surrogate for non-mercury toxic metal emission limits. Table 11 lists PM emission control methods for pulverized coal units.

Table 11. PM Emissions Control Methods

Methods of Control	
ESP	Method – Electrostatic capture of PM, high capture efficiency Reagent – None Typical Fuel Types – Solid fuels Capital Costs – High Co-benefits – Capture particle-bound mercury
Baghouse	Method – Filtration of PM, highest capture efficiency Reagent – None Typical Fuel Types – Gaseous fuels Capital Costs – High Co-benefits – High capture of mercury and other HAPs
Co-benefit Methods of Control	
Scrubber (wet or dry)	Method – Captures PM

Electrostatic Precipitator

An electrostatic precipitator (ESP) uses an electrical charge to separate the particles in the flue gas stream under the influence of an electric field. More than 70 percent of existing coal-fired power plants are reported to have installed ESPs.[63]

In brief, an ESP works by imparting a positive or negative charge to particles in the flue gas stream. The particles are then attracted to an oppositely charged plate or tube and removed from the collection surface to a hopper by vibrating or rapping the collection surface. An ESP can be installed at one of two locations. Most ESPs are installed downstream of the air heater, where the temperature of the flue gas is between 130°C-180°C (270°F-350°F).[64] An ESP installed downstream of the air heater is known as a "cold-side" ESP. An ESP installed upstream of the air heater, where flue gas temperatures are significantly higher, is known as a "hot-side" ESP.

The effectiveness of an ESP depends in part on the electrical resistivity of the particles in the flue gas. Coal with a moderate to high amount of sulfur produces particles that are more readily controlled. Low sulfur coal produces a high resistivity fly ash that is more difficult to control. The effectiveness of an ESP also varies depending on particle size. An ESP can capture greater than 99 percent of total PM, while capturing 80 to 95 percent of PM$_{2.5}$.[65]

Depending upon the particular ESP and the applicable MACT standards, there may not be any need for further controls; however, many ESPs are decades old and were built for compliance with less stringent emission standards in mind. As a result, these facilities may need to make one or both of the following modifications to comply with new MACT standards:

- Upgrade of existing ESP – The existing ESP could be upgraded through addition of new electric fields, use of new high frequency transformer rectifier technology, or other changes. The applicability of this option will depend upon the condition and performance of the existing ESP.

- Replacement of ESP with fabric filter – A fabric filter may be installed in place of the existing ESP. In some cases, the existing ESP casing and support structure could be utilized for the baghouse. A booster fan is likely to be necessary because of the increased pressure drop across the fabric filter.

In recent years, there has been more focus on fabric filters for PM control than ESPs because of the PM capture advantages of fabric filters. As a result, there is not a great deal of available information on recent cost or installation time for ESPs. In general, however, an ESP will likely cost somewhat more and take more time to construct than a fabric filter built for the same gas flow rate because ESPs are somewhat more complex to build than a fabric filter system.

Fabric Filter or Baghouse

A fabric filter, more commonly known as a baghouse, traps particles in the flue gas before they exit the stack. Baghouses are made of woven or felted material in the shape of a cylindrical bag or a flat, supported envelope. The system includes a dust collection hopper and a cleaning mechanism for periodic removal of the collected particles.

According to EPA, a fabric filter on a coal-fired power plant can capture up to 99.9 percent of total particulate emissions and 99.0 to 99.8 percent of $PM_{2.5}$.[66] Thirty-five percent of coal-fired power plants in the U.S. have installed fabric filters.[67]

A full baghouse retrofit would generally cost somewhat more than the addition of a downstream polishing baghouse (discussed later); however, because the material and erection of the baghouse is only a portion of the total retrofit cost of any baghouse, most of the costs are the same (ductwork, booster fans, dampers, electrical system modifications, etc.). Increasing the fabric filter size by 50 percent (equivalent to a change in air to cloth ratio of 6.0 to 4.0) would yield much less than a 50 percent impact to project cost over the cost of retrofitting a polishing baghouse, perhaps in the range of 15-20 percent. A fabric filter retrofit (full or polishing) would typically be achievable in 12-24 months from design to completion, depending upon the complexity of the ductwork necessary. For example, in 2009, the Reid Gardner generating station in Nevada completed the installation of three new pulse-jet baghouses in 17 months. The retrofit required the replacement of the plant's existing mechanical separators.[68]

Rather than replacing an ESP with a fabric filter, a power plant with an existing ESP has the option of installing a downstream polishing baghouse (downstream of the existing ESP). This will capture particulate matter that escapes the ESP. Retrofit of a downstream polishing fabric filter will require addition of ductwork, a booster fan, and the fabric filter system. Costs will vary by application, particularly by the amount of ductwork needed. For example, the polishing fabric filter installed on three 90 MW boilers at Presque Isle Power Plant in Michigan cost about $125/KW (2005$). This project, however, had very long duct runs for each of the boilers and significant redundancy.[69] For a project on a single larger unit without the long duct runs, one would expect a lower cost.

Co-benefits of PM controls – PM controls, especially fabric filters, permit higher co-benefit mercury capture. Also, capture of other toxic pollutants through DSI is improved with a fabric filter. This is true with any situation where sorbent is used to capture a pollutant because a fabric filter permits capture on the filter cake in addition to capture in-flight while ESPs permit only in-flight capture.

Control of Dioxins and Furans

Under the Air Toxics Rule, EPA has proposed a "work practice" standard for organic HAPs, including emissions of dioxins and furans, from coal-fired power plants. Power plant operators would be required to perform an annual tune-up, rather than meeting a specific emissions limit. EPA has proposed a work practice standard because it found that most organic HAP emissions from coal power plants are below current detection levels of EPA test methods. Therefore, it concluded that it is impractical to reliably measure emissions of organic HAPs. While EPA is not proposing numerical emission limits for organic HAPs, for completeness, we discuss below experience in controlling emissions of dioxins and furans from incinerators that may have relevance for co-benefits with coal power plant controls.

Emissions of dioxins and furans result from: (1) their presence in the fuel being combusted; (2) the thermal breakdown and molecular rearrangement of precursor ring compounds, chlorinated aromatic hydrocarbons; or (3) from reactions on fly ash involving carbon, oxygen, hydrogen, chorine, and a transition metal catalyst. Because dioxins and furans are generally not expected to be present in coal, the second and third mechanisms are of most interest. In both of these mechanisms, formation occurs in the post-combustion zone at temperatures over 500°C (930°F) for the second mechanism or around 250-300°C (480-575°F) for the third mechanism.[70] Once formed, dioxins and furans are difficult to destroy through combustion. Therefore, it is best to prevent their formation, or alternatively, capture them once formed.

While emissions of dioxins and furans have long been a source of concern for municipal and other waste incinerators, their emissions have not generally been controlled from power plants. Emissions of dioxins and furans are generally expected to be lower in coal combustion than in municipal waste combustion because of the relatively lower chlorine levels and the higher sulfur levels of coal.[50] Sulfur has been shown to impede dioxins and furans formation.[50,70,71] Table 12 lists the technologies for control of dioxins and furans and EPA's previously proposed institutional, commercial, and industrial boiler limits for pulverized coal units.

The extensive experience with control of dioxins and furans at incinerators has provided insights that may be relevant for power plants, while recognizing the important differences between power plants and incinerators. Because dioxins and furans are formed from organic precursors, one way to avoid their formation is to have complete combustion of organics; hence, combustion controls or oxidation catalysts can contribute to their lower formation.[70] SCR has also been shown to mitigate emissions of dioxins and furans.[50,51] Data indicate that capture of chlorine prior to the dioxins formation temperature will reduce dioxins/furans formation from municipal waste combustors.[58] Therefore, dry sorbent injection upstream of the air preheater of a coal boiler may be a means of reducing dioxins/furans formation.

Injection of activated carbon is a means that has been used to capture dioxins and furans emitted by municipal waste incinerators,[50, 70] and has demonstrated over 95 percent capture of dioxins at a hazardous waste incinerator.[72] Currently, there are not enough available data to form a definitive conclusion about how effective ACI will be at dioxins/furans capture from power plants because of the different conditions. The information available, however, suggests that it is likely to be useful in reducing dioxins and furans in the event other methods are not adequate in preventing their formation.

Table 12. Dioxins and Furans Emission Control Methods

Methods of Control	
Activated Carbon Injection (ACI)	Method – Activated carbon adsorbs gaseous dioxins/furans, and is captured in downstream PM control device Reagent – Powdered Activated Carbon Typical Fuel Types – Any fuel, but downstream PM control needed Capital Costs – Low Co-benefits – Capture of Hg
Co-benefit Methods of Control	
Combustion Controls	Method – Destruction of organic dioxins/furans precursors
Dry Sorbent Injection	Method – Captures precursor chlorine prior to dioxins/furans formation
CO or NOx Catalyst	Method – Catalyst increases oxidation of organic dioxins/furans precursors

Labor Availability

The installation of air pollution control equipment requires the effort of engineers, managers, and skilled laborers, and past history has shown that the industry has substantial capacity to install the necessary controls. Between 2008 and 2010, coal-fired power plants added approximately 60 GW of FGD controls and almost 20 GW of SCR controls with a total of 80 GW of FGD controls installed under CAIR Phase 1. Between 2001 and 2005, the electric power industry successfully installed more than 96 GW of SCR systems in response to the NOx SIP Call.

Based on a retrospective study of actual retrofit experience, it was determined that EPA and industry dramatically underestimated the ability of the air pollution control industry to support the utility industry in responding to CAIR. The study offered several reasons for why EPA and industry underestimated the capabilities of the labor market: (1) boilermakers will work overtime during periods of high demand; (2) boilermakers frequently travel to different locations for work, supplementing local available labor; (3) boilermakers work in fields other than power, such as refining/petrochemical, shipbuilding, metals industries and other construction trades, and workers can shift industry sectors with appropriate training; and (4) new workers will enter the field—for example, in advance of the NOx SIP Call, boilermakers increased their ranks by 35 percent, mostly by adding new members.[73]

In November 2010, the Institute of Clean Air Companies (ICAC), an association that represents most of the suppliers of air pollution control technology, sent a letter to U.S. Senator Thomas Carper confirming the nation's air pollution control equipment companies repeatedly have successfully met more stringent NOx, SO_2, and mercury emission limits with timely installations of effective controls and are well prepared to meet new EPA requirements. In its letter, the industry association stated, "based on a history of successes, we are now even more resolute that labor availability will in no way constrain the industry's ability to fully and timely comply with the proposed interstate Transport Rule and upcoming utility MACT rules. Contrary to any concerns or rhetoric pointing to labor shortages, we would hope that efforts that clean the air also put Americans back to work."[74] Also in November 2010, the Building and Construction Trades Department of the AFL-CIO issued a letter concluding that "[t]here is no evidence to suggest that the availability of skilled manpower will constrain pollution control technology development."[75]

The electric industry has long been aware that EPA would be regulating HAPs and other pollutants from coal-fired power plants. As a result, many companies started planning their compliance strategies before EPA even proposed its Air Toxics Rule in March 2011. For example, companies have been evaluating control technology options and establishing capital budgets.[76] Similar advance planning occurred after the proposed CAIR rule was released in December 2003. In 2004, when EPA was still working to finalize the rule, companies placed orders for more than 20 GW of FGD controls (wet and dry scrubbers).[77] Southern Company, for example, had begun planning its FGD installations in 2003, well in advance of the final rule.[78]

Conclusion

EPA's clean air rules—the Transport Rule and the Air Toxics Rule—address one of the nation's largest sources of toxic air pollution, providing important human health protections to millions of people throughout the country. Additionally, thousands of construction and engineering jobs will be created as companies invest in modern control technologies.[79]

The electric power sector has several decades of experience controlling air pollution emissions from coal-fired power plants, which should serve the industry well as it prepares to comply with the Transport Rule and the Air Toxics Rule. Many companies have already moved ahead with the upgrades necessary to comply with these future standards, demonstrating that better environmental performance is both technically and economically feasible.

In most cases, the required pollution control technologies are commercially available and have a long track record of effective performance at many coal-fired power plants in the U.S., with some operating successfully for decades. The electric power sector has demonstrated that it is capable of installing pollution controls on a large portion of the nation's generating fleet in a relatively short period of time. Also, suppliers have demonstrated the ability to deliver pollution control equipment in a timely manner, and the skilled labor needed to install it should be available to meet the challenge as well.

Endnotes

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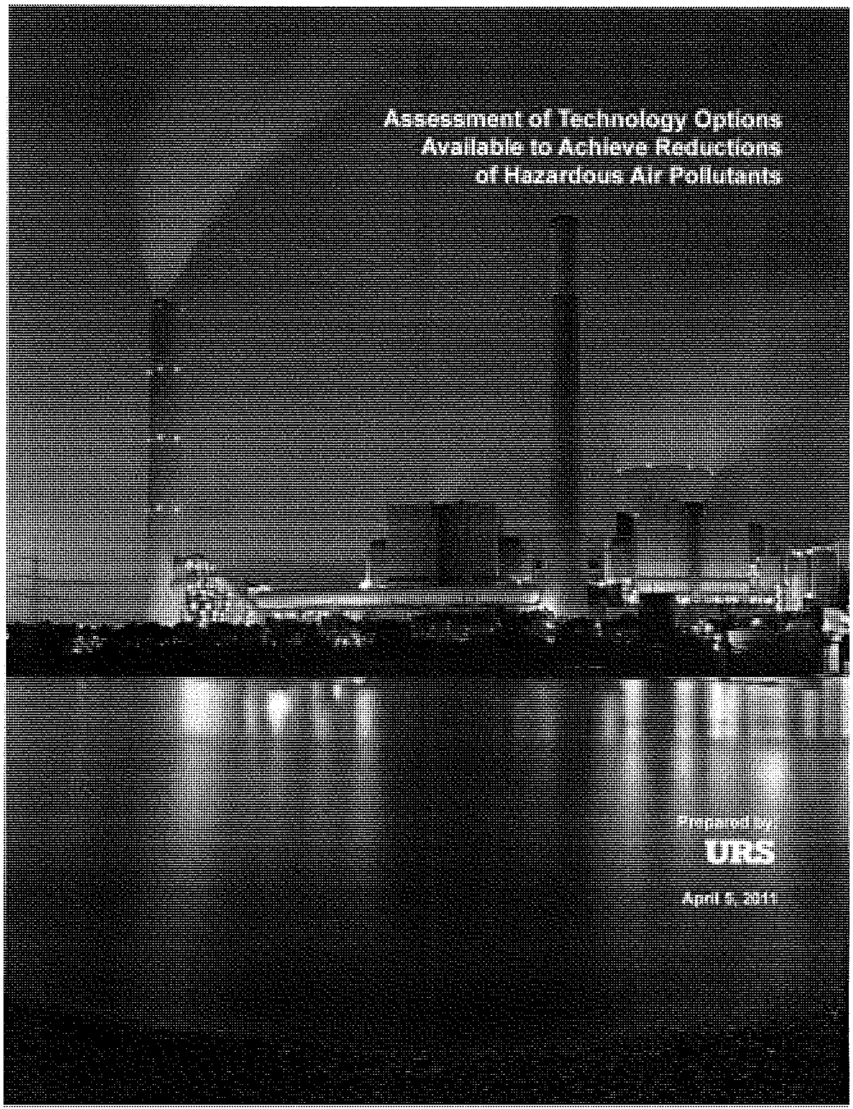

Assessment of Technology Options
Available to Achieve Reductions
of Hazardous Air Pollutants

Prepared by:
URS

April 5, 2011

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Appendix A Technology Descriptions

Index of Acronyms

ACI	Activated Carbon Injection
AH	Air Heater
AQC	Air Quality Control
CAA	Clean Air Act
CFB	Circulating Fluidized Bed
CO	Carbon monoxide
COHPAC	Compact Hybrid Particulate Collector
DSI	Dry Sorbent Injection
EMPC	Estimated Maximum Possible Concentration
ESP	Electrostatic Precipitator
FF	Fabric Filter
FGD	Flue Gas Desulfurization
FGDd	Dry Flue Gas Desulfurization (Spray dryer or circulating fluidized bed scrubber)
FGDw	Wet Flue Gas Desulfurization
HAP	Hazardous Air Pollutant
HCl	Hydrochloric Acid
HCN	Hydrogen cyanide
Hg	Mercury
ICI	Industrial, Commercial, and Institutional
ICR	Information Collection Request
LOI	Loss on Ignition
MACT	Maximum Achievable Control Technology
NESHAP	National Emission Standards for Hazardous Air Pollutants
NSR	Normalized Stoichiometric Ratio
PM	Particulate Matter
PRB	Powder River Basin Coal
RICE	Reciprocating Internal Combustion Engine
SBS	Sodium Bisulfate
SCR	Selective Catalytic Reduction
SOFA	Separated Over-Fire Air
SO_3	Sulfur Trioxide
TEF	Toxic Equivalency Factor
TEQ	Toxicity Equivalent
UPL	Upper Prediction Limit
ZWD	Zero Water Discharge

Executive Summary

This report[1] describes the results of an assessment conducted by URS Corporation (URS) to evaluate the availability of pollution control technologies to meet the requirements of the proposed National Emission Standards for Hazardous Air Pollutants (NESHAP) for Utility Electric Generating Units ("EGUs") (the "Toxics Rule"). This assessment was designed to answer the ultimate question of whether control technologies are available that will equip EGUs to meet the emission limitations the Environmental Protection Agency (EPA) has proposed, regardless of current configuration. URS identified proven, commercially available control technologies that will enable EGUs to achieve compliance with the Toxics Rule, given adequate investment by the owners. In the event that an EGU requires the installation or upgrade of control equipment, the technologies available typically require less than three years to install after detailed design and permitting is complete.

To begin, URS identified a number of typical control equipment configurations present at existing EGUs. An assessment was performed to evaluate additional control technologies appropriate for those configurations that would enable EGUs to comply with the Toxics Rule emission limitations on hazardous air pollutants ("HAP"). URS consulted its own experience and database of pollution control technologies and reviewed published literature, conference proceedings, expert analysis and procurement information regarding the availability, cost and efficacy of numerous available control technologies. URS applied this information and its own experience to evaluate the menu of control options that would be available to EGUs of different configurations, and to rank those options. This analysis took into account the performance, maturity and number of existing commercial installations of the control technologies. While special cases may exist, this analysis demonstrates that the Toxics Rule emission limitations are generally achievable through the application of proven, commercially available technologies, regardless of the starting configuration of the facility.

Assuming EPA signs the final Toxics Rule as scheduled on November 16, 2011, the rule will not be effective until early 2012, or 60 days after it is published in the Federal Register. EGUs will not be required to comply with the Toxics Rule until three years after the effective date, or early 2015 – nearly four years after proposal. To the extent that existing facilities require additional control technology to comply with the Toxics Rule, the technology is known, available and the industry has demonstrated its ability to install and to operate these controls.

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[1] This report was prepared by URS Corporation for Exelon Corporation.

The controls that will be most commonly needed, such as activated carbon injection (for mercury control) or dry sorbent injection (for SO_3 control on bituminous fired plants and acid gas control at some western sub-bituminous fired EGUs) typically require less than eighteen months to install once permitting is completed. Barring unreasonable permitting or supply chain delays, EGU owners who act promptly will be able to complete such low capital upgrades by the compliance date. Facilities requiring high capital upgrades such as the addition of wet FGDs will face longer installation times. Owners of EGUs requiring such additions will need to select technologies and contractors and to file permit applications promptly to meet the 2015 compliance deadline. For those facilities facing unique challenges in completing necessary upgrades by 2015, EPA has indicated that it will provide extensions of up to one year.

1.0 Introduction

In performing this assessment, URS considered the emissions limitations proposed by EPA in the Toxics Rule, reviewed relevant commercially available control technologies and evaluated seven hypothetical configurations of existing control equipment to determine whether such facilities could be brought into compliance with the proposed Toxics Rule emission limitations. It was concluded that: 1) in many instances, no additional controls would be required; 2) where additional controls would be necessary, the most common top-ranked control technologies can typically be installed in less than 24 months; and 3) in all other instances considered in this assessment, the top-ranked control technology can typically be installed in less than 36 months after detailed design and permitting is complete.

2.0 Technology Survey

2.1 EPA's Proposed Emission Limitations

In the Toxics Rule, EPA proposes emissions limitations for five different sub-categories of EGUs. Coal-fired EGUs are divided into lignite, non-lignite and integrated gasification/ combined cycle ("IGCC") sub-categories. Oil-fired EGUs are divided into solid fuel (petroleum coke) and liquid fuel sub-categories. EPA has proposed emission limitations for mercury, hydrogen chloride ("HCl") and total particulate matter ("PM") for all coal-fired EGU sub-categories and the solid fuel oil sub-category, with HCl being a surrogate for all acid gases and PM being a surrogate for non-mercury HAP metals. For liquid oil-fired EGUs, EPA has proposed limits on total HAP metals (including mercury), HCl and hydrogen fluoride ("HF"). EPA has proposed to regulate dioxins/furans and other organic HAPs for all sub-categories through work practice standards rather than numerical emission limitations. EPA has also proposed a number of alternative compliance methods. For example, coal-fired EGUs may use sulfur dioxide ("SO_2") as a surrogate for acid gases in certain circumstances, and may test for total non-mercury HAP metals or ten individual HAP metals in lieu of complying with the PM limitation.

2.2 URS' Technology Survey

URS conducted a review of commercially-available air quality control ("AQC") technologies that may be employed by coal- and oil-fired EGUs in order to meet emission limitations proposed by EPA in the Toxics Rule. This technology survey presents control technologies for Mercury, HCl, and PM, the default emission limitations in the Toxics Rule for coal-fired EGUs and solid fuel oil-fired EGUs.[2] Although EPA proposed different emission limitations for liquid fuel oil-fired EGUs, the technologies available for controlling PM and HCl at other EGUs would control total HAP metals and HF (as well as HCl) at liquid fuel oil-fired EGUs.

To conduct the control technology assessment, URS utilized internal information on air quality control technologies, as well as information from published literature and conference proceedings, discussions with technology experts, and procurement information associated with some technologies. For each pollutant category, air quality control technologies were evaluated for their ability to achieve sufficient performance levels. Although costs were not a primary factor in the selection of appropriate technologies, they were considered when comparing different technologies with similar expected performance levels. The multi-pollutant nature of various technologies was also considered, as some processes would be expected to effectively remove pollutants from a number of potential HAP categories, allowing a holistic approach to achieving compliance with the Toxics Rule. Through this analysis, a ranking of available control technologies was developed that takes into account cost, maturity and the ability to treat multiple HAPs. This assessment did not consider possible technologies for controlling dioxin/ furan emissions or organic HAPs. Under the proposed Toxics Rule, these HAPs are to be controlled through work practice standards.

The analysis demonstrates that there is a range of control technologies available to EGUs requiring additional levels of control for mercury, HCl or PM. These technologies are proven and mature, and in fact are already installed at many EGUs. Many of the available technologies involve relatively low capital retrofits that typically require less than eighteen months to install. Some technologies, such as wet or dry scrubbers, have longer installation times and EGU owners requiring such additions will need to move more rapidly to meet the 2015 compliance deadline.

2.3 Assumptions Regarding Existing Sources

URS assessed AQC technologies for expected performance, cost, and schedule to construct at power plants of several different configurations. It should be noted that for any particular facility, technology assessments must be conducted on a site-specific basis, taking into account the plant's existing equipment, current operating scenarios, physical layout and balance of plant considerations, as well as economic and long-term planning considerations. For the purposes of this study, several common configurations of AQC technology already in place at existing fossil-fuel fired facilities were identified to address expected need for additional controls to reduce the emissions of toxic air pollutants. These hypothetical configurations consist of one or a combination of control technologies for PM, SO_2 or oxides of nitrogen ("NO_x").

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[2] URS did not specifically address the applicability of any particular technology to IGCC units.

The most common PM control technologies are fabric filters ("FFs") and electrostatic precipitators ("ESPs"). The most common SO_2 controls are flue gas desulfurization ("FGD") systems (commonly called "scrubbers"), which can be either wet ("FGDw") or dry ("FGDd"). The most common NO_x controls are selective catalytic reduction ("SCR") systems.

The potential need for additional controls to comply with the Toxics Rule was evaluated for seven different hypothetical configurations of AQC technology at existing EGUs, as presented in Table 2-1. The objective of the assessment was to present the most plausible technologies for each plant configuration to achieve the HAP emission limitations. This analysis does not indicate that all plant configurations will need additional controls; nor does it imply that any particular controls installed at a specific plant will unequivocally meet the emission limitations proposed in the Toxics Rule. The analysis is intended as an overview of commercially available, proven technologies that may potentially be employed in order to lower emissions of the targeted HAP species for a given plant configuration. The analysis took into account cost as well as the performance, maturity level, and number of existing commercial installations of each technology. Selected technologies included different control processes that could be implemented for different fuel types, including opportunities for fuel switching. Additionally, the ability of certain technologies to control multiple HAPs was considered when making final selections.

2.4 Summary of Survey Results

URS identified several alternative control strategies that could be deployed where these hypothetical configurations will likely require additional control for PM, HCl and mercury. Up to four different technologies were identified for each scenario, each of which would provide the additional level of control required. Those technologies were then ranked according to the criteria described above. Table 2-1 lists several alternatives for each configuration requiring additional control. Each facility would choose one of these alternatives to achieve compliance with the Toxics Rule, based on the site-specific conditions at that facility. As the table reflects, many facilities with existing PM and SO_2 controls may need no additional controls to meet the PM and HCl limits in the Toxics Rule, respectively.[3] However, if the controls at such facilities are already at their maximum capacity or face other operational challenges, these facilities may indeed need additional controls for PM or HCl as well. Suggestions are provided for upgrades and add-on controls for these outlier plants in the discussion in Section 3.0.

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[3] These configurations are noted in the table as "no additional control needed."

In Table 2-1, configurations that are unlikely to need additional controls to comply with the Toxics Rule are shaded in green. Those likely to require additional controls that can be installed in no more than 24 months are shaded in blue. Those likely to require additional controls that can be typically installed in 36 months (but require more than 24 months) are shaded in yellow. Installation times for new controls are not cumulative. Rather, EGU owners installing multiple control technologies would schedule installation of those controls, and any ancillary modifications to the plant, during the same planned outage, or a coordinated series of outages, provided all controls could be installed prior to the deadline for compliance with the Toxics Rule. Nonetheless, if a particular control cannot be installed prior to this deadline, it is probable that controls necessary for other HAPs would be installed separately, because these control technologies are not, by and large, interdependent.

Section 3.0 of this report provides brief discussions of the rationale behind the various technology selections for each of the hypothetical configurations considered. For each configuration, the report provides strategies for controlling PM, HCl and mercury. Appendix A presents further information on the technologies discussed in this report, including each technology's maturity; the number of commercial installations, if known, the technology's expected performance; capital and operating costs; and the typical schedule for design, installation, and startup.

Table 2-1. Pollution Control Options for Coal- and Oil-Fired Power Plants[4]

Existing Configuration	Control Options to Achieve Toxics Rule Emission Limitations		
	PM	HCl	Hg
Fabric Filter only (§ 3.2)	*No additional control needed*	1) FGDd; or 2) FGDw; or 3) Dry Sorbent Injection;[5] or 4) Coal switch	1) ACI with SO_3 control; or 2) FGDw with re-emission additives; or 3) Combustion Modification; or 4) Coal switch
Fabric Filter with Wet Flue Gas Desulfurization (§ 3.3)	*No additional control needed*	*No additional control needed*	1) ACI with SO_3 control; or 2) FGD additives; or 3) Bromide addition
Fabric Filter with Dry Flue Gas Desulfurization (§ 3.4)	*No additional control needed*	*No additional control needed*	1) ACI with SO_3 control; or 2) Bromide addition
Fabric Filter with Dry Flue Gas Desulfurization and Selective Catalytic Reduction (§ 3.5)	*No additional control needed*	*No additional control needed*	1) ACI with SO_3 control; or 2) Bromide addition; or 3) Coal switch
Electrostatic Precipitator with Wet Flue Gas Desulfurization and Selective Catalytic Reduction (§ 3.6)	1) ESP upgrade; or 2) Scrubber upgrade; or 3) Toxecon; or 4) Wet ESP	*No additional control needed*	1) ACI with SO_3 control; or 2) Bromide addition; or 3) FGDw re-emission additives; or 4) Toxecon
Electrostatic Precipitator only (§ 3.7)	1) ESP upgrade; or 2) Toxecon; or 3) Wet ESP; or 4) FGDw	1) FGDd/FF; or 2) Toxecon w/ Dry Sorbent Injection; or 3) Coal switch; or 4) FGDw	1) Toxecon; or 2) ACI with SO_3 control; or 3) FGDw + Bromide; or 4) Coal switch
Electrostatic Precipitator with Wet Flue Gas Desulfurization (§ 3.8)	1) ESP upgrade; or 2) FGDw upgrade; or 3) Toxecon	*No additional control needed*	1) ACI with SO_3 control; or 2) Bromide addition; or 3) FGDw re-emission additives; or 4) Toxecon

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[4] Green highlighting indicates that additional controls are unlikely to be necessary to achieve Toxics Rule emission limitations. Blue highlighting indicates that the top-ranked control technology has installation times of 24 months or less, after permitting. Yellow highlighting indicates that the top-ranked control technology has typical installation times of more than 24 months but less than 36 months, after permitting.

[5] Dry sorbent injection includes Trona, hydrated lime, SBS and other reagents.

3.0 Analysis of Control Alternatives

3.1 Overview

With adequate investment, it should be possible for virtually any EGU to comply with all emission limits under the Toxics Rule, but the required strategy for meeting these limits will depend on each plant's existing control configuration. The following sections present seven typical air pollution control configurations at fossil-fuel fired power plants, as listed in Table 2-1. Each regulated HAP (or surrogate) is discussed in terms of the plant configuration and likely controls that may be necessary or useful in achieving EPA's proposed mercury and air toxics limits. Through the reasoning that is presented in the sections below, technologies have been selected as the most likely to assist in meeting EPA's proposed mercury and air toxic standards, as presented in Table 2-1. Technologies discussed in this section are all commercially available technologies with a history of demonstrated performance, and each is capable of achieving compliance with the Toxics Rule. It is acknowledged that site specific factors will impact the ultimate performance of any AQC technology at a given plant. Additional technologies in the developmental stages may be available and have not been included in the scope of this survey. For further detail on these technologies see Appendix A.

3.2 Fabric Filter Configuration

3.2.1 Particulate Matter (PM)

A properly sized and functional FF should provide adequate PM control to comply with the Toxics Rule. If a facility is in need of additional removal, one option would be to add a wet scrubber after the baghouse to remove additional PM as well as HCl. Toxecon could also be added (downstream carbon injection and baghouse) if multi-pollutant control is desired, as this system provides not only additional PM control, but mercury control as well.

3.2.2 Hydrochloric Acid (HCl)

Plants equipped with a properly sized and functional fabric filter capable of controlling PM emissions and with a sufficient additional margin could adequately control emissions of HCl with the installation of a dry FGD system. FGDd would be effective for relatively high HCl content and, for this configuration, would be less costly than FGDw. However, additional PM emissions can be expected with the operation of an FGDd system; therefore, for units with a FF that is not capable of controlling additional PM loadings, a wet FGD would be an effective way to control both HCl and PM.

For plants burning bituminous coal, switching to a western sub-bituminous coal would appreciably reduce HCl emissions. If coal substitution alone does not achieve compliance for these plants, dry sorbent injection will be sufficient to treat the reduced load of HCl. For plants already burning PRB coal and configured with an efficient FF, dry sorbent injection can be expected to reduce HCl emissions sufficiently to meet the Toxics Rule emission standard, and will be significantly less costly than a wet or dry scrubber.

3.2.3 Mercury (Hg)

For plants equipped with a properly sized and functional fabric filter capable of controlling PM emissions and with a sufficient additional margin, an activated carbon injection (ACI) system will provide adequate Hg control. FFs usually respond well to ACI for Hg removal, assuming the FF can handle the additional PM loading resulting from the operation of the ACI. However, fly ash sales may be impacted by ACI installation upstream of the FF due to increased carbon levels in the collected fly ash. Additionally, under this configuration, control of SO_3, which tends to hinder the effectiveness of ACI Hg removal, may be necessary for effective operation of ACI when burning high sulfur coal.

If mercury re-emissions from the wet FGD system cause the EGU to exceed the Toxics Rule emission limitation, the use of scrubber additives to reduce the re-emissions may be more cost-effective than ACI.

If further Hg control is needed, using Low NO_x Burners or increasing their NO_x removal performance can lead to higher Loss on Ignition (LOI) to the fly ash, and better Hg removal.

Some plants firing bituminous coal might be challenged to achieve Hg emission limitations due to SO_3 interference with sorbent-based mercury control processes. Plants firing lignite (particularly Texas lignite) will require high levels of removal in order to comply with the Toxics Rule. However, in both cases, a switch to western sub-bituminous coal could appreciably lower mercury emissions. In the case of bituminous coals this would be through decreasing flue gas SO_3 concentrations, and thus increasing the performance of ACI for Hg control. For Texas lignite coals, Hg emissions would likely be lowered due to significantly lower fuel Hg concentrations, as well as moderate improvement in ACI performance.

3.3 Fabric Filter and Wet FGD Configuration

3.3.1 Particulate Matter (PM)

Plants equipped with FF and FGDw are unlikely to require additional controls to meet the PM emission limitation in the Toxics Rule. If additional control is required, a plant could upgrade either its fabric filter or scrubber, or both, to achieve the PM emission limitation.

3.3.2 Hydrochloric Acid (HCl)

Plants equipped with FF and FGDw are unlikely to require additional controls to meet the HCl emission limitation in the Toxics Rule.

3.3.3 Mercury (Hg)

For plants equipped with a properly sized and functional fabric filter capable of controlling PM emissions with a sufficient additional margin, an activated carbon injection (ACI) system will provide adequate Hg control. FFs usually respond well to ACI for Hg removal, assuming the FF can handle the additional PM loading resulting from the operation of the ACI. However, SO_3 control may be necessary for effective operation of ACI when burning high sulfur coal.

If mercury re-emissions from the wet FGD system cause the EGU to exceed the Toxics Rule emission limitation, the use of scrubber additives may be able to reduce re-emission of mercury more cost-effectively than ACI.

Finally, although less effective without a selective catalytic reduction (SCR) system, bromine addition could be sufficient for trimming emissions at EGUs firing low sulfur coal if the Hg emission rate needs only small incremental improvement.

3.4 Fabric Filter-Dry FGD Configuration

3.4.1 Particulate Matter (PM)

Plants equipped with FF and FGDd are unlikely to require additional controls to meet the PM emission limitation in the Toxics Rule. If additional control is required, a plant could upgrade either its fabric filter or scrubber, or both, to achieve the PM emission limitation.

3.4.2 Hydrochloric Acid (HCl)

Plants equipped with FF and FGDd are unlikely to require additional controls to meet the HCl emission limitation in the Toxics Rule. However, if needed, a dry sorbent injection system would provide a low capital option to trim emissions.

3.4.3 Mercury (Hg)

For plants equipped with a properly sized and functional fabric filter capable of controlling PM emissions with a sufficient additional margin, an Activated Carbon Injection (ACI) system will provide adequate Hg control. FFs usually respond well to ACI for Hg removal, assuming the FF can handle the additional PM loading resulting from the operation of the ACI. However, SO_3 control may be necessary for effective operation of ACI when burning high sulfur coal.

Finally, although less effective without a selective catalytic reduction (SCR) system, bromide addition could be sufficient for trimming emissions at EGUs firing low sulfur coal if the Hg emission rate needs only small incremental improvement.

3.5 SCR-FGDd-FF Configuration

3.5.1 Particulate Matter (PM)

Plants equipped with SCR, FF and FGDd are unlikely to require additional controls to meet the PM emission limitation in the Toxics Rule. If additional control is required, a plant could upgrade either its FF or scrubber, or both, to achieve the PM emission limitation.

3.5.2 Hydrochloric Acid (HCl)

Plants equipped with SCR, FF and FGDd are unlikely to require additional controls to meet the HCl emission limitation in the Toxics Rule. If necessary, removal rates would be improved by either upgrading the scrubber or installing a dry sorbent injection system.

3.5.3 Mercury (Hg)

For plants equipped with a properly sized and functional fabric filter capable of controlling PM emissions with a sufficient margin, an activated carbon injection (ACI) system will provide adequate Hg control. FFs usually respond well to ACI for Hg removal, assuming the FF can handle the additional PM loading resulting from the operation of the ACI. However, SO_3 control may be necessary for effective operation of ACI when burning high sulfur coal.

Removal rates of Hg from bromide addition are high in combination with the SCR, especially for PRB coal, and could also provide polishing capability for bituminous coals that require only incremental improvements in removal. However, the SCR, FGDd, FF configuration is not typical for plants firing bituminous coal. If installed on a bituminous coal plant, it is possible that mercury control performance could be constrained by elevated SO_3 levels. A switch to Western sub-bituminous coal would improve the performance of the plant's various mercury controls as well as yield acid gas emission reductions.

3.6 SCR-ESP-Wet FGD Configuration

3.6.1 Particulate Matter (PM)

The compliance strategy for PM under this configuration will depend on the performance of existing controls. Assuming the existing ESP does not provide adequate control to meet the Toxics Rule emission limitation, the first option to provide additional control would be an upgrade of the ESP, the scrubber mist eliminator, or both. Alternatively, a wet ESP may be installed. Toxecon could also be added downstream of the existing ESP if multi-pollutant control is desired.

3.6.2 Hydrochloric Acid (HCl)

Plants equipped with a high-efficiency wet FGD system are unlikely to require additional controls to meet the HCl emission limitation in the Toxics Rule. If additional removal is needed, removal efficiencies could be improved by one or more of the FGD upgrades described in Appendix A.

3.6.3 Mercury (Hg)

The Hg control strategy under this configuration would depend on the fuel being fired. The primary choice for plants firing bituminous coal would likely be ACI with additional SO_3 control technology; some plants with this configuration might not require any additional mercury control. For plants firing low-sulfur fuels, the primary choice would likely be bromine addition. For plants requiring additional PM control, or desiring Hg removal upstream of the FGD system, Toxecon with activated carbon injection would likely be the best control strategy. Under this configuration, scrubber re-emissions additives may be required to control Hg emissions in conjunction with other control technology, depending on mercury removal performance of the wet FGD.

3.7 ESP Only Configuration

3.7.1 Particulate Matter (PM)

The compliance strategy for PM under this configuration will depend on the performance of existing controls. Assuming the existing ESP does not provide adequate control to meet the Toxics Rule emission limitation, the first option for additional control would be an upgrade of the ESP. Alternatively, a wet ESP may be installed. Toxecon could also be added downstream of the existing ESP if multi-pollutant control is desired. In some cases, particularly plants burning bituminous fuels, a wet FGD may be installed if additional SO_2 control is also desired.

3.7.2 Hydrochloric Acid (HCl)

A dry FGD system will provide effective control for relatively high HCl content, but may require installation of a fabric filter to control the additional particulate loadings dry FGD would add. A dry FGD system is likely to be more cost effective than a wet FGD, if switching to a FF to handle the additional particulate loading is not necessary. Toxecon used in conjunction with sorbent injection would be a viable control option if multi-pollutant control is desired. For plants firing bituminous coal, a switch to a western coal would reduce the HCl loading on the ESP, likely enabling dry sorbent injection alone to achieve the Toxics Rule emission limitation.

3.7.3 Mercury (Hg)

The Hg control strategy under this configuration would depend on the fuel being fired. For plants burning western coals, or those requiring additional PM control or desiring Hg removal upstream of the FGD system, Toxecon with activated carbon injection would likely be the best control strategy. Alternatively, an ACI system using brominated sorbent may be used for plants burning western coals; however, mercury removal under this option depends on ESP performance. Installation of a wet FGD may be a viable option for plants that desire additional SO_2 control; using this strategy, bromide addition may also be an option for mercury control for EGUs firing western fuels.

The primary choice for a plant firing bituminous coal would likely be an ACI with additional SO_3 control technology. However, plants firing bituminous coal will be challenged to achieve desired mercury reductions due to SO_3 interference. Plants firing lignite containing high mercury levels (e.g., Texas lignite) will require high levels of removal which are difficult to obtain across an ESP. In both cases, a switch to a low-sulfur sub-bituminous coal would lower mercury emissions via better mercury control performance and, for Texas lignite fired EGUs, lower coal mercury levels.

3.8 ESP-FGDw Configuration

3.8.1 Particulate Matter (PM)

The compliance strategy for PM under this configuration will depend on the performance of existing controls. Assuming the existing ESP does not provide adequate control to meet the Toxics Rule emission limitation, the first option to provide additional control would be an upgrade of the ESP, the scrubber mist eliminator, or both. Alternatively, Toxecon could also be added downstream of the existing ESP if multi-pollutant control is desired.

3.8.2 Hydrochloric Acid (HCl)

Plants equipped with a high-efficiency wet FGD system are unlikely to require additional controls to meet the HCl emission limitation in the Toxics Rule. If additional removal is needed, removal efficiencies could be improved by one or more of the FGD upgrades described in Appendix A or by or a dry sorbent injection system.

3.8.3 Mercury (Hg)

The Hg control strategy under this configuration would depend on the fuel being fired. For plants requiring additional PM control or desiring Hg removal upstream of the FGD system, Toxecon with activated carbon injection would likely be the best control strategy. Bromine addition would likely be the primary control strategy for plants burning low-sulfur fuels. Alternatively, for plants burning low-sulfur fuel, ACI is another control option. ACI would also be an option for plants firing bituminous coal, but SO_3 control technology may be necessary Under this configuration, scrubber re-emission additives may be required to control Hg emissions in conjunction with other control technology, depending on mercury removal performance of the wet FGD.

3.9 Installation Schedule

None of the typical configurations considered in this assessment included existing mercury controls, though many EGUs are presently equipped with ACI. Accordingly, this analysis concludes that every EGU configuration would require mercury control, and identifies ACI as the technology of choice for six of the seven configurations considered. ACI has a typical installation time of 12 to 18 months after permitting. As URS assumes fabric filters to provide adequate PM control to comply with the Toxics Rule PM emission limitation, ESP upgrades are the top-ranked alternative for improving PM control from EGUs. Depending on the scope of the upgrade, installation times for ESP upgrades typically run from six months for the simpler upgrades to twenty-four months for the most comprehensive upgrades. Dry FGD technology, with a typical installation time of 24 to 36 months, was identified as the top-ranked technology for only two of the seven configurations evaluated. Dry FGD has the longest installation time of the top-ranked technologies.

These installation times are not cumulative; rather, plants installing multiple technologies would typically coordinate installation so that all controls for mercury, HCl and PM would be installed during the same outage, although some additional outage time may be necessary to co-ordinate simultaneous installation. With nearly four years between the proposal of the Toxics Rule and the date EGUs must come into compliance, these improvements can be accomplished on-time, provided EGU owners move quickly to initiate these upgrades in response to the proposed rule, and no unreasonable delays occur in the permitting process or supply chain.[6]

4.0 Conclusion

Using the emission limitations proposed by EPA in the Toxics Rule as its guide, URS examined the existing field of demonstrated, available AQC technologies to determine whether these technologies would be sufficient to allow typical coal-fired and oil-fired EGUs to achieve these emission limitations. URS concluded that the emission limitations proposed in the Toxics Rule can be achieved by typical EGUs through the application of successfully demonstrated, available AQC technologies. The controls considered in this analysis can typically be installed in 18 months (for ACI), 24 months (for ESP upgrades), or 36 months (for FGDs) after detailed design and permitting is complete. If EGU owners make their technology choices and initiate the permitting process promptly, they should be able to comply with the Toxics Rule emission limits by the deadline of early 2015 (almost 48 months after proposal of the rule). Plants facing extreme delays in permitting or the supply chain, or with atypically complex upgrade requirements, have an opportunity to request an additional year to come into compliance with the Toxics Rule.

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[6] Potential delays associated with heavy equipment lead times have not been included in this analysis because it is not possible to predict at this time whether any particular delay will occur.

APPENDIX A

A.0 Technology Descriptions

This section provides a high-level overview of each add-on control technology that has been presented in the main body of this report. Because some of these technologies treat multiple HAPs, they cannot easily be categorized by the pollutant they treat. However, several of the technologies described are upgrades or modifications to AQC systems present at existing EGUs. These modifications are grouped separately from technologies not considered in the hypothetical configurations discussed in Section 3.0 of the report.

Equipment costs provided in the following technology descriptions are typical; site specific circumstances may lead to higher or lower costs due to site specific requirements. Additionally, cost estimates include equipment and operating costs, where specified; planning and financing costs are not included. The estimated schedules for implementation of the technologies represent time from the placement of the equipment order to installation. This assessment is based on cost and schedule information available today, and the estimates provided here may be affected by future changes in pricing and scheduling demand.

A.1 Modifications to Existing AQC Systems at EGUs

A.1.1 Cold-side ESP Upgrades

The use of electrostatic precipitator (ESP) technology for the removal of PM is well established and has been implemented for over 100 years. Decades old, or poorly performing ESPs that were designed for lower emission performance can be upgraded to improve collection efficiency and reduce operating costs. Often the performance can be increased through a thorough examination to insure that worn or broken components are replaced, and insuring that the gas flow distribution through the system is uniform. Other ESP modifications and upgrades may include:

- Upgrade of control systems such as power controlled rapping (PCR). $0.27/kW
- Upgrade of ESP power supplies. $1/kW
- Add SO_3 and/or ammonia injection (to the flue gas upstream of the ESP) to improve ash agglomeration. $2-10/kW
- Replace wire and weight systems, widening the gas passages and adding rigid discharge electrodes. This will improve the mechanical integrity of the electrodes and can improve performance with existing TR sets.
- Increase the number of electrical bus sections.
- Add rappers to decrease the amount of collecting surface area served by each rapper

- Increase the collecting surface area - several vendors report that many of the older ESPs in the US can be modified to increase the collecting surface area by 10-20% within their existing footprint. Another option is to add an additional field. $30-0/kW
- Reduce gas flow through the ESP by repairing upstream leaks or upgrading air heaters to limit air in-leakage
- Add a Bipolar Agglomerator to the inlet of the ESP. $25-40/kW.

The capital costs associated with these upgrades will depend on the extent to which the ESP is modified. If the unit is particularly old or poorly performing, more repairs or modifications may be necessary. Some vendors claim that modifications such as upgrading the power supplies and controls will pay for themselves within one to two years due to savings in power consumption. Operating costs for many of these modifications will not increase over the cost of previous operation, and in many cases the operating costs will decrease due to gains in collection and power consumption efficiency. The operating costs for injecting SO_3 and/or ammonia for ash conditioning will be approximately 2-4 $/kW-yr.

Another method to improve the performance of an ESP would be to add a Bipolar Agglomerator to the ESP inlet duct. An agglomerator manufactured by Indigo Technologies uses a bipolar charging zone to charge part of the dust positively and part of the dust negatively. This is accomplished by passing the flue gas through a series of alternating positive and negative parallel passages. The dust then enters a mixing zone where the oppositely charged particles are attracted to each other and form a larger agglomerated particle that can be more easily removed in the ESP. The agglomerator is similar to an ESP without collection plates. This technology is relatively new with only 45 commercial installations at power plants, mostly outside the U.S. Reductions in opacity are reported to be 40% to 70%, with some units burning sub-bituminous and bituminous fuels reporting reductions in opacity of approximately 50%. The cost to add an agglomerator to an existing system is approximately $25-40/kW. The operating costs are approximately $0.02/kW-yr and consist primarily of the power required to operate the unit.

- ESP UpgradeTechnology Maturity: mature
- Number of Units Upgraded: hundreds
- Expected Performance:
  - PM: +99%
- Capital Costs: 0.27 - 20 $/kW
- Operating Costs: .02- 4 $/kW-yr.
- Installation Schedule: 6-12 months from award of design to operation for low capital options; 12-24 months for implementation of higher capital cost modifications / additions
  - **Outage Required:** 0-7 days if no plate/electrode modification. 2-4 weeks with plate/electrode modification.

A.1.2 Fabric Filter Upgrades

A typical fabric filter should be able to meet MACT PM emission standards. If a plant is unable to meet emission standards with a fabric filter, the cause is most likely due to bag failures. To minimize bag failures it may be possible to optimize the cleaning process to minimize these problems. On a pulse jet baghouse this may include adjusting the pulse pressure and duration to more thoroughly clean the bags. By cleaning more thoroughly, the interval between cleaning may be reduced and the life of the bags could be extended. Optimization of fabric filter performance may also be achieved by an evaluation of the maintenance schedule. An analysis of process and maintenance data could lead to an understanding of how to anticipate bag failure and replace them before the failure actually occurs.

Another alternative to increase PM collection would be to replace the existing bags with different material such as a membrane bag. Different bag materials will have different pressure drop characteristics and it will be necessary to determine whether the plant has existing fan capacity to handle the upgrade.

An additional solution would be to add additional compartments to the existing baghouse to increase the collection surface, or add a COHPAC system. The Toxecon could be necessary if a multi-pollutant strategy is desired and it is advantageous to maintain fly ash sales from the existing baghouse. Adding additional compartments or a Toxecon system are both capital intensive solutions and may not be practical for plants that have restricted space available for retrofit.

- **Technology Maturity:** mature (fabric filter)
- **Number of Commercial Installations:** many
- **Expected Performance:**
  - PM: +99%
- **Costs for Optimizing Fabric Filter Performance:** $200K - $500K, excluding projects where complete bag replacement is required
- **Schedule:** 3-6 months for performance optimization
- **Costs for Adding Compartments or Toxecon:** 75-130 $/kW
- **Schedule:** 12-24 months from detailed design to startup
  - **Outage Required:** 7-10 days. (3-4 weeks if a new fan is required)

A.1.3 FGDw Additives

As discussed in Section 1.2.8, wet scrubbers can remove acid gases, PM and mercury. However, removal of Hg^{+2} by wet FGD systems can be limited by a phenomenon called "re-emission" that results in a portion of the scrubbed Hg^{+2} being chemically reduced to Hg^0 in the FGD liquor. Once reduced, the insoluble Hg^0 is released back into the flue gas. The re-emission process is not currently well understood, but is believed to occur by reaction with bisulfite ions (dissolved SO_2 at lower Ph) in the FGD liquor, according to the following overall reaction:

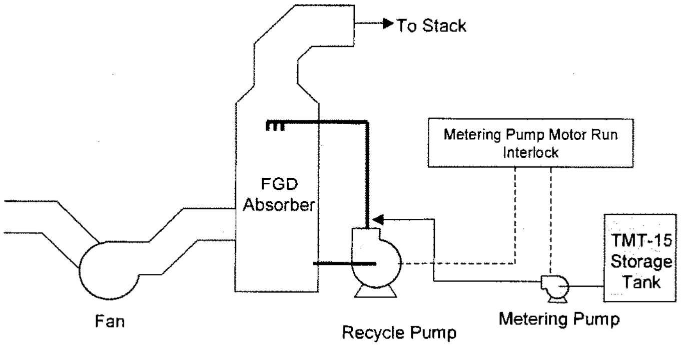
$$Hg^{+2} + HSO_3^- + H_2O \leftrightarrow Hg^0 + SO_4^= + 3\ H^+$$

The main pathway for this reaction is believed to be through the formation of complexes between Hg^{+2}, sulfite, chloride, and possibly thiosulfate ions (present in inhibited oxidation FGD systems). Even in forced oxidation FGD systems, there can be sufficient sulfite present for re-emission reactions to occur. As more is understood, it may be possible to control FGD chemistry to minimize re-emission (e.g., by controlling forced oxidation air rates and/or liquor chloride concentrations). However, a near-term solution may be the use of FGD additives to precipitate Hg^{+2} out of the liquid phase before it undergoes reduction reactions.

Additives generally work by rapidly precipitating oxidized mercury from the FGD liquor, so it will not react with other liquid-phase species such as sulfite ions and be reduced to the elemental form. Most additives contain sulfides, which produce a very insoluble salt with oxidized mercury.

The most straightforward method of adding sulfides to FGD systems might be to introduce H_2S into the scrubbed gas upstream of the FGD absorber. However, H_2S is extremely toxic and most utilities would not want to handle this gas at their plants. Another approach is to add sulfide-containing salts to the FGD liquor. However, some of these salts can release H_2S if they are exposed to low Ph, aqueous conditions. Four commercially available additives are discussed below: Degussa's TMT-15, Nalco's additive 8034, Babcock & Wilcox's sodium hydrosulfide (NaHS) additive, and Solucorp's IFS-2C additive. Figure A-1 shows a schematic for a sample TMT-15 addition system.

Figure A-1. TMT-15 Additive System for FGD Absorber with One Recycle Pump



One operational issue that has not fully been addressed is the impact of re-emission additives on gypsum Hg content. Some owners of FGDw systems sell the gypsum that is produced as a byproduct of the scrubber. An increase in the mercury content of the gypsum byproduct could affect sales of the product. Currently there are few if any specifications on gypsum Hg content, but re-emission additives that precipitate mercury could increase gypsum Hg content to the point where the gypsum would potentially no longer be salable. If this is the case, the effective cost of re-emission additives would increase for those FGDw operators who are no longer able to sell the gypsum byproduct for $5-10/ton, but rather a liability costing $5-20/ton to dispose of in a landfill.

- **Technology Maturity:** Testing 3 years of experience
- **Number of Commercial Installations:** Several, in Europe
- **Expected Performance:**
  - Hg – An additional 10-50% above native capture
- **Capital Costs:** 0.75-1.5 $/Kw
- **Operating Costs:** 0.2-0.5 $/Kw-yr.
- **Installation Schedule:** 6-9 months for design, installation, and parametric testing.
  - **Outage Required:** None.

A.1.4 Flue Gas Desulfurization (FGD) Upgrades

Existing FGD scrubber units can be modified to enhance SO_2 removal performance and improve unit operations and reliability. Such modifications are applicable to older FGD units, units currently not being operated (i.e., moth-balled units) or units originally designed for lower removals than now required or desired. The extent of a given upgrade process is typically a function of the required performance levels, configuration and condition of the existing absorber, and other site-specific balance-of-plant requirements.

Upgrades to a scrubber can offer an appreciable cost advantage over replacing an existing FGD unit with either a new unit or an alternative air quality control technology. This is achieved by salvaging as many structural components and equipment associated with the existing unit as possible. This includes reuse of existing structural steel and absorber shells as well as high-capital process equipment such as pumps and compressors (where applicable).

Upgrades have been performed on a large number of FGD units over the past 15 years and have resulted in increased SO_2 removal performance to levels ranging from 92 – 99%. These have ranged from minor modifications to the internal components of a given unit, to enhance gas-liquid contact, to conversion of some units from one FGD technology to another coupled with the addition or modification of various balance-of-plant equipment or processes. An example of a technology conversion could include modifications to change a dual-alkali scrubber to a limestone forced-oxidation unit.

Because of the large variation of activities and associated costs that are possible within the range of scrubber modifications that can be implemented, it is convenient to classify upgrades into three different categories, as described below.

- Minor Upgrades: These consist of moderate changes to some of the internals of a scrubber module, reusing most of existing process and structural components. The primary focus is enhancement of gas/liquid contacting within the absorber. Examples of applicable modifications include installation of absorber trays or wall rings as well as modifications to the configuration or type of reagent spray headers used (to improve overall reagent coverage and overlap within the absorber). Typical minor upgrades have been used to boost FGD performance to 92 – 97% SO_2 removal.
- Moderate Upgrades: These upgrades typically consist of major overhauls to the internals of a scrubber module to replace poor performing or failing components. In many cases, the existing internal process and structural components are removed; the absorber shell and large equipment components are maintained. Modifications include installation of new and improved reagent spray header arrays and absorber trays.
- Major Upgrades: For some old FGD units, systems operating with lower-efficiency technologies and units that have been out of commission for extended periods of time, major upgrades are required obtain desired levels of performance. Such upgrades typically involve the same activities described for moderate upgrades, but can also include additional replacement of some large equipment along with modifications or additions associated with balance-of-plant equipment. The latter can include additions of or modifications to reagent preparation systems (e.g., ball mills), byproduct dewatering systems, and process slurry recirculation systems. In some cases, enhancements are made to existing mist eliminators to reduce carry-over of particulate material from the scrubber. Conversions from one FGD technology to another may include demolition of old or unneeded process components and/or addition of new ones.

The costs associated with FGD system upgrades are commensurate with the level of capital improvements or replacements required for a specific unit. The costs for minor upgrades typically range from $5 - $10/kW, whereas moderate upgrades typically range from $15 - $25/kW. The costs for major upgrades can be quite variable, depending on the nature of upgrade and extent of balance-of-plant modifications made; these upgrades typically range from $50 to no more than $100/kW. The pending EPA MACT rule coupled with the multi-pollutant control nature of wet FGD scrubbers should ensure that scrubber upgrades continue to be a feasible option for many plants to enhance emission reductions.

The impact of a scrubber upgrade on unit operating costs is determined by the nature of the modification(s). Changes in reagent preparation and process transport costs are impacted by the nature of the modifications made to preparation equipment, recirculation lines, and spray headers. For example, increased pressure-drop across the reagent slurry recirculation system (i.e., due to increased number of spray headers) would result in increased energy costs to operate the process. The addition of improved contactors within the absorber vessel may enable slurry liquid-to-gas ratios to be reduced, thus having an opposite effect on costs. The addition of new processes associated with byproduct dewatering or water treatment would increase operating costs to varying degrees. A transition to a zero water discharge (ZWD) system could result in elimination of the need for a water treatment system, thus having the opposite effect; however, this benefit would be off-set by higher capital cost and energy usage required for the ZWD scheme. Furthermore, the conversion to an FGD process that produces a marketable gypsum byproduct could result in an appreciable revenue stream for the plant if local market conditions are favorable. Thus, operating cost impacts of scrubber upgrades can vary substantially from plant to plant, ranging from actually reducing operating costs to significantly increasing operating costs, depending on the nature of the existing and modified units.

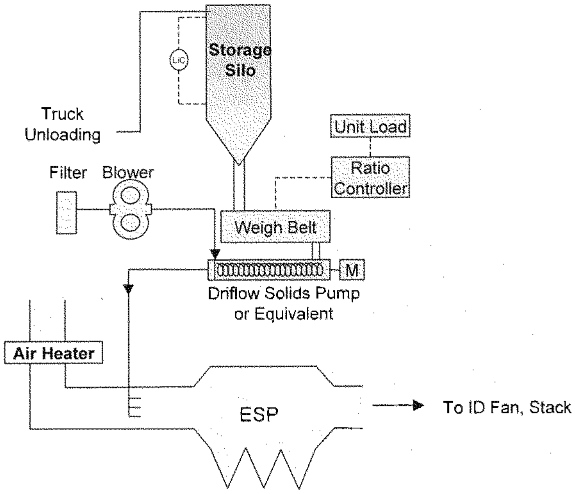
- **Technology Maturity**: FGD scrubber upgrades have been conducted over 15 years.
- **Number of Commercial Installations:** Approximately 50 FGD units have been upgraded to enhance performance or lower overall operating costs.
- **Expected Performance:**
  - SO_2: Upgraded FGD scrubbers have SO_2 removal rates of 92 – 99%.
  - PM: High-efficiency FGD units can typically remove up to 70% of the particulate material entering the absorber in the flue gas.
  - HCl: Most well-performing wet FGD units are able to achieve greater than 90% removal of hydrogen halides. HCl would be expected to be removed across a wet FGD unit at a similar or higher efficiency than SO_2.
- **Capital Costs:**
  - Minor Upgrades: $5 - $10/kW
  - Moderate Upgrades: $15 - $25/kW
  - Major Upgrades: $50 - $100/kW
- **Operating Costs:**
  - Variable (see discussion above)
- **Installation Schedule:** Typical schedules for the design, installation, and startup of FGD upgrades range from 12 – 36 months.
  - **Outage Required:** 4-8 weeks, in two parts.

A.2 Additional AQC Technologies and Process Changes

A.2.1 Activated Carbon Injection (ACI)

Activated carbon injection (ACI) is the most demonstrated of the add-on mercury control technologies considered. Figure A-2 illustrates how ACI would be implemented upstream of a cold-side ESP (injection upstream of a FF baghouse would look similar, except for exchanging a baghouse for the ESP). Sorbent is metered from a storage silo with a weigh belt or volumetric feeder. A blower provides the motive force to convey the sorbent from the feeder to the flue gas duct. The sorbent is injected into the flue gas duct via a series of injection lances. The lances are placed upstream of the PM control device (PCD) or in rare cases upstream of the air heater.

Figure A-2. Simplified Schematic of ACI Installation.



The performance of ACI for mercury control can be very site specific. Factors such as duct residence time, mixing effectiveness, PCD size and type, flue gas temperature, flue gas HCl concentration, concentrations of competing species in the flue gas (e.g., SO_3) and other factors make it difficult to use full-scale performance data from one site to predict performance at another. Each of these parameters is explored below in somewhat more detail.

- The more important design factor for the lances is the promotion of mixing between the activated carbon and the flue gas. Better mixing can be achieved through nozzle design on the lances and careful lance placement. These parameters can be optimized with the help of computational fluid dynamics (CFD) modeling, in which the trajectory of the injected sorbent particles is computed throughout the flue gas path.
- PCD size can be important because carbon/ash carryover from small PCDs can limit the injection rate. Carbon carryover has been visually observed on PM filters placed at the outlet of small and large ESPs, but quantification of the carryover is difficult. URS experience with ACI in front of one small ESP (SCA = 173 ft^2/kacfm) (DOE project DE-FC26-03NT41987) showed that the injected carbon adversely affected ESP sparking, due to carbon tracking on insulators. Increased sparking could limit the amount of carbon that can be injected and hence the mercury capture that can be achieved.
- ACI performance is best at lower flue gas temperatures (<300°F). Carbons are being developed for high temperature applications, such as Sorbent Technologies' H-PAC. At temperatures below 650°F, H-PAC is reputed to have the same mercury removal performance as Sorbent Technologies' standard brominated carbon B-PAC.

- Activated carbon injection performs poorly in flue gas with high SO_3 concentrations, such as flue gas derived from eastern bituminous coals. The SO_3 competes with mercury for adsorption sites on the activated carbon. SO_3 tolerant sorbents (discussed below) and SO_3 mitigation technologies (discussed in a previous section) are possible means to make ACI more effective for bituminous flue gas.
- For low-halogen flue gas, brominated sorbents can offer significantly higher mercury removal than standard activated carbons. Brominated carbons have shown only a small advantage for high chloride flue gas, likely because SO_3 concentrations are high in these types of gases.

There are no data to predict the long-term effects of a permanent activated carbon injection process that is in operation for several years. As noted above, increased sparking has been observed on small ESPs. Carbon breakthrough has been observed on both small and large ESPs. Carbon breakthrough may compromise gypsum quality for units that are equipped with wet FGDs downstream of the ESP. Carbon breakthrough may also trigger New Source Review for units that do not have additional PM controls downstream of the ESP.

A disadvantage of using ACI for mercury control is that the carbon in the fly ash can adversely affect the air entrainment capabilities of concretes made using fly ash to replace some of the cement. The carbon sorbent in the fly ash competitively adsorbs the air-entraining admixtures (AEAs) that are added to concrete for air entrainment and stabilization. This competition results in a larger volume of AEA being needed, and more significantly to ready-mix concrete manufacturers, it results in variability in the amount of AEA needed.

- **Technology Maturity:** Testing & Full Scale Operation; ~10 & 2 years of experience
- **Number of Commercial Installations:** 50+
- **Expected Performance:**
    - Hg – An additional 10-90% above native capture
- **Capital Costs:** 2-10 \$/kW (depending upon unit size)
- **Operating Costs:** 2-20 \$/kW-yr.
- **Installation Schedule:** 12-18 months for design, installation, and parametric testing.
    - **Outage Required:** None.

A.2.2 Dry Sorbent Injection ("DSI")

Sorbent materials can be injected at various points along the flue gas path to control acid gases. The main target of this technology is SO_3; however additional acids may also be removed such as HCl, HF, and SO_2. The removal of these additional gases depends on the amount and type of material added to the system. Sorbent reagents can be injected either as slurry or as a dry material. Slurry is typically injected using dual fluid nozzles where the water evaporates upon injection leaving dry sorbent material to react with the acid gases in the flue gas. Dry material is injected using pneumatic conveyors to carry the material to the injection point. Sorbent injection is a mature technology with approximately 90 units currently being treated with one of five main reagents:

- Trona – (22 units) dry injection of a mined mineral consisting of sodium bicarbonate and sodium carbonate
- SBS – (20 units) liquid injection of soda ash or sodium bisulfite
- Hydrated Lime – (28-34 units) dry injection
- Magnesium Hydroxide – (1 unit) slurry
- Ammonia – (8 units) anhydrous or aqueous

Sorbents can be injected at several locations along the flue gas path including into the boiler, before an SCR, before the air heater, before the ESP or fabric filter, or before an FGD system. Table A-1 illustrates injection locations for each Sorbent material and includes the typical SO_3 removal rate at normalized stoichiometric ratios (NSR) of reagent to SO_3. Ammonia is currently used to condition fly ash for removal in an ESP, and could be used for SO_3 control; however the stoichiometric ratio must be carefully regulated to prevent excess ammonia emissions. This may be an attractive option for plants with an existing SCR and infrastructure for ammonia storage on site.

Table A-1. Injection Locations, SO_3 Removal, and Required Stoichiometric Ratio

Typical Injection Location	**Trona**	**SBS Injection**	**Hydrated Lime**	**Magnesium Hydroxide**	**Ammonia**
Boiler				●	
Before SCR		●			
Before AH	●	●		●	
Before ESP/FF	●		●		●
Before FGD			●		
Typical SO_3 Removal	70-90%	95-99%	50-80%	50-90%	80-95%
Typical NSR	2-3	1-1.5	3-5	2-4	1.5-2

The typical capital cost for this technology is about $10/kW with the exception of ammonia injection that is approximately $5/kW. This includes pumps, spray nozzles, and control equipment. The operating costs consist of the reagent, maintenance, water, and parasitic power costs. A majority of the operating cost (~80%) consists of the reagent feed stock, thus making the overall operating cost dependent upon the normalized stoichiometric ratio necessary to get the desired removal rate. The NSR listed in the table above is for SO_3, additional reagent will be necessary to capture HCl and HF in some plant configurations. SO_2 capture is also possible by injecting excess reagent; however the PM collection device must be capable of handling the increased PM load, which may be 50-80% greater than the fly ash alone. Table A-2 contains a summary of conceptual capital and approximate costs.

Table A-2. Capital and Operating Costs for Dry Sorbent Injection

	Trona	SBS Injection	Hydrated Lime	Magnesium Hydroxide	Ammonia
Capital Cost ($/kW)	10	10	10	10	5
Reagent Cost ($/ton)	180	275	125	500	600
Approx. Operating Costs for SO_3 and HCl capture ($/kW-yr.)	3.4 - 5	2 - 2.75	2 – 3	5.1 - 8.6	2.2 - 3.5

- **Technology Maturity:** mature; 7+ years of operating experience
- **Number of Commercial Installations:** 90
- **Expected Performance:**
  - SO_3 – 50 - 99% depending on reagent, injection rate and configuration
  - HCl, HF – up to +90%
  - SO_2 – 40 - 90% possible
  - Hg – enhances ACI performance by removing SO_3 especially in bituminous flue gas
- **Capital Costs:** 5 - 10 $/kW
- **Operating Costs:** 2 - 8.6 $/kW-yr. ($SO_3$ only)
- **Installation Schedule:** 9-12 months from award to commercial operation
  - **Outage Required:** None.

A.2.3 Coal Switching

With upcoming MACT limits on HCl and mercury emissions at coal fired power plants, there are several scenarios where coal switching may be a cost-effective option for meeting emission limits, rather than the installation of pollution control devices. There are likely to be two dominant cases where coal switching is a viable option for meeting the upcoming MACT standards:

- Switching from an Eastern bituminous or Lignite coal to a Powder River Basin (PRB) coal to meet HCl emissions limits.
- Switching from Lignite (Texas-derived in particular) to a PRB coal to meet mercury emissions limits.

For units switching from bituminous coal, it is recognized that the feasibility would depend on the ability of a given plant to operate either with higher coal flow (and associated flue gas volume) or at a de-rated capacity.

Without some form of scrubber (wet or dry) it is unlikely that a plant burning eastern bituminous coal could meet the potential HCl emission limits. Installation of a new FGD system or a significant overhaul of an existing FGD system would be capital intensive project, and cost approximately $100/Kw or more. PRB coals have approximately 20-100 times less chloride and

4-10 times less sulfur than eastern bituminous coals. By switching to a PRB coal, it could be possible to meet

HCl emission limits by using a less expensive HCl control technology like alkaline injection. For this switch to be economically favorable, the following would have to be true:

- The site burns eastern bituminous or a lignite coal with significant chloride and sulfur content.
    - The site does not have any HCl control technologies in place, or has a significantly under-performing HCl control technology that would need a significant overhaul to meet HCl emissions limits.
    - The site has a FF or ESP that can handle additional PM loading from alkaline injection for HCl removal. A FF would be more effective in removing HCl with alkaline injection than an ESP, and would also likely be more able to meet PM emissions limits even with the additional PM load.

Due to the high content of mercury in lignite, it is unlikely that a plant using lignite as its only fuel source would economically be able to meet a non-coal specific mercury emission limit. Therefore, complete fuel switching, or if significant pollution control equipment was already in place with high native capture (SCR, FF, FGD), fuel blending would be necessary to meet the emissions limits. Due to similar energy content, availability, and relatively low cost, the most likely candidate for an alternate fuel is PRB coal.

A.2.4 Combustion Modifications

Boiler combustion modifications may be used to optimize mercury capture by unburned carbon, which is subsequently collected along with fly ash in the ESP. It has been observed in limited field testing reports that for bituminous coal fired plants significant mercury control percentages (up to 75%) can be achieved with fly ash having elevated LOI values.[7]

One research organization, G.E. Environmental Services, has conducted full-scale tests on using combustion modifications to optimize this effect. The full-scale tests were co-funded by the U.S. Department of Energy. One project (DE-FC26-03NT41725) has employed coal "re-burning" to optimize mercury capture, while the other (DE-FC26-05NT42310) is investigating air staging using (separated over-fire air [SOFA]).

In the first demonstration project, GE reported up to 60% mercury removal with optimized re-burning and 10-15% LOI in the fly ash at a 300°F ESP inlet flue gas temperature. They reported up to 75% mercury removal at similar conditions, but with a lower, 270°F ESP inlet temperature. In the second project on a 200-MW tangentially-fired unit, GE reports that optimized SOFA achieved up to 65% mercury removal with about 5% LOI in the fly ash at a 300°F ESP inlet temperature. They reported a strong effect of flue gas temperature on mercury capture by LOI, and tested duct humidification as a means of lowering the ESP inlet flue gas temperature.

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[7] Lissianski, Vitali. "Mercury Control Using Combustion Staging". Presented at DOE-NETL Mercury Control Technology R&D Program Review. Pittsburgh, PA. July 13, 2005.

The Lehigh University Energy Research Center also has been investigating the effects of boiler combustion modifications on mercury emissions. They have developed a predictive model, and have conducted full-scale tests at three eastern-bituminous-coal-fired units, ranging from 108- to 650-MW in size. Two sites also fire some imported coals. In testing on a 250-MW tangentially fired boiler, they were able to enhance capture of mercury with the fly ash from a baseline level of about 6% to about 60% with "optimum" low mercury settings and a mid-level excess oxygen value. Variables optimized included excess oxygen, coal mills in service, mill classifier setting, separated over-fire air (SOFA) percentages, burner and SOFA tilt, air heater exit temperatures, and flue gas residence time prior to PM removal. The latter was accomplished by de-energizing an old ESP upstream of a new, larger ESP. However, the 60% mercury reduction level was achieved in some tests without de-energizing the old ESP.

Combustion modification, to increase mercury capture, will increase carbon content in the fly ash. If the ash is being sold, increased carbon content could either reduce the value or render the ash unsalable. Such costs can be significant when ash goes from being a commodity worth $5-20/ton to a liability costing $5-20/ton to dispose of in a landfill.

There are not many studies available on combustion modification and its impact on mercury removal on PRB coal fired power plants. Part of this is due to the general efficiency in combustion of PRB coals, and that achieving an LOI of greater than 1 wt% is difficult. Due to low SO_3 concentrations in the flue gas and the highly alkaline ash, even small increases in LOI have been shown to increase Hg capture.

Based on the evidence at hand, combustion modification may possibly be used for mercury control either in conjunction with another mercury control technology when native capture is low, or as a way of increasing a high native removal such that no other mercury control technologies are necessary. Combustion modification will be most effective if a baghouse is used for PM capture, as increased LOI will be more effective with fabric filters than with ESPs.

- **Technology Maturity:** Testing; ~10 years of operating experience
- **Number of Commercial Installations:** few operating
- **Expected Performance:**
  - NO_x – 0-20% additional removal
  - Hg – An additional 10-50% above native capture
- **Capital Costs:** 0.5-1 $/kW (Study necessary to "tune")
- **Operating Costs:** 0.2-1 $/kW-yr. (http://www.epa.gov/airmarkets/progsregs/epa-ipm/docs/v410/Chapter5.pdf)

- **Installation Schedule:** 3-6 months for experimental design and "tuning" of the combustion tests.
  - **Outage Required:** None.

A.2.5 Dry Flue Gas Desulfurization

Dry FGD (also referred to as a "spray dryer") is typically employed for the removal of SO_2 emissions, but may also be used to accomplish removal of acid gases and selenium. Removal of these additional species may be necessary to achieve anticipated emissions standards under the Toxics Rule. In a spray dryer absorber vessel, flue gas comes in contact with an atomized slurry of alkaline reagent and recycled solids for removal of SO_2 and acid gases. The alkaline reagent, typically lime, reacts with incoming pollutants to form calcium salts, such as calcium sulfate, calcium chloride, and calcium fluoride. Solids from the scrubber are captured in a downstream fabric filter. A portion of the reaction products and fly ash are recycled to the reagent slurry feed and the remaining are transported to landfill for disposal. The spray dryer technology, a type of dry flue gas desulfurization (dry FGD), operates at 20-30° F above saturation temperature, and as such, does not generate a wastewater purge stream as in a wet FGD, or limestone forced oxidation (LSFO) system. Spray dryers are limited in removal capabilities for higher sulfur coals compared to their wet FGD counterpart, and scrubber vessels are limited in size, generally treating up to 350 MW for a single vessel.

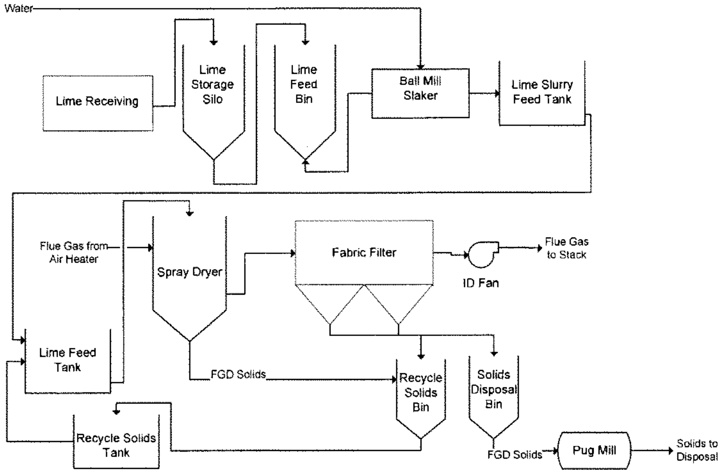
The spray dryer technology represents a mature technology that has over 30 years of operating experience, including operation at several of Exelon's facilities. Although spray dryers have traditionally been employed for SO_2 emissions reduction from coal-fired power plants, tbey have also been shown to effectively remove acid gases (HCl, HF), and particulate with the downstream fabric filter, to meet anticipated MACT limits.

The lime spray dyer may be appropriate for removal of particulate, acid gases, and selenium and SO_2 at facilities that do not currently employ a scrubber system. Facilities with an existing electrostatic precipitator (ESP) or fabric filter (FF) may choose to continue operation of the existing particulate control device in order to maintain flyash sales or they may opt to abandon existing particulate control devices, relying on the spray dryer's downstream fabric filter for particulate control, and disposing of all fly ash and FGD solid byproduct.

A general process flow diagram of the lime spray dryer is shown in Figure A-3. Major capital cost components of a lime spray dryer system include the following systems:

- Lime reagent supply and handling equipment,
- Absorber vessel and associated pumps and tanks,
- Flue gas handling systems (duct work and ID fans), and
- Waste/byproduct handling systems.

Figure A-3. Lime Spray Dryer FGD System



The spray dryer system requires a significant engineering effort and footprint at the plant site. Capital costs will be affected by the type of fuel, the desired removal efficiency, specific site arrangement and existing equipment considerations. Typical capital costs for a lime spray dryer system would likely be in the range of $220-260/kW. Additional project costs will be incurred including engineering, construction, and general facilities that are not accounted for in the above range. Operating costs for the lime spray dyer include lime reagent, water use, maintenance, parasitic power, and solids disposal costs. Lime reagent is a major operating cost, generally on the order of $100+/ton. Operating costs are typically around $50-80/kW-yr, again highly dependent upon site-specific factors such as fuel type, system removal efficiency, reagent and disposal costs.

- **Technology Maturity:** mature; 30+ years operating experience
- **Number of Commercial Installations:** many
- **Expected Performance:**
  - SO_2 – 95%, dependent on fuel sulfur content
  - Acid Gases – up to 95% HCl, 45-95% HF, depending on coal properties
  - Hg – up to 90% when combined with carbon injection
- **Capital Costs:** Dependent upon unit size, site-specific factors
- **Operating Costs:** 30-50 $/kW-yr
- **Installation Schedule:** 24-36 months from detailed design to start-up

A.2.6 Halogen Injection

In this technology, halogen-containing chemicals are injected into the furnace to supplement the coal chlorine in its effect on mercury oxidation. Halogen salts added are typically calcium bromide ($CaBr_2$). These salts, added with the coal or injected into the furnace, decompose at furnace temperature to form HBr/Br_2 in the flue gas. These vapor-phase halogen acids react with elemental mercury in the back pass of the furnace as the flue gas cools, to produce oxidized mercury that can be removed by a downstream wet FGD system.

Full-scale tests of furnace halogen injection have been conducted on a number of coal-fired units that fire Powder River Basin coal, Texas lignite, and North Dakota lignite. Results from these parametric tests have shown that low concentrations of bromine (20-200 ppm in the coal) can produce 50-90% oxidized mercury in the flue gas.

For example, calcium bromide injection tests were conducted at TXU's Monticello Steam Electric Station Unit 3, which is equipped with a cold-side ESP and a limestone forced oxidation scrubber. Monticello fires a 50/50 blend of PRB and Texas Lignite. Baseline mercury removal at the unit ranges from 10 to 40%. Two two-week continuous injection tests were conducted at rates equivalent to 55 ppm and 113 ppm Br in the coal. At an injection rate equivalent to 55 ppm Br in the coal, the oxidation of mercury at the FGD inlet was 67%, and the removal of mercury was 65% (computed from coal and FGD outlet gas Hg concentrations). At an injection rate equivalent to 113 ppm Br in the coal, the oxidation of mercury at the FGD inlet was 85%, and the overall removal of mercury was 86%.

Parametric and long term testing at other sites have shown that bromide addition is most effective with coals that are low in chloride (PRB) and at plants that have an SCR. The SCR, in conjunction with the bromine, act to oxidize the elemental mercury better than either individually.

The long-term effects of bromine injection on FGD chemistry and FGD or boiler materials of construction are not known. To date, the longest test durations have been sixty days, which is not long enough to evaluate corrosion effects. It is also not known if the increased concentration of bromine in the fly ash and scrubber liquor/solids will impact the reuse of these byproducts.

Capital equipment to be installed for the furnace halogen injection process is relatively simple, much like the equipment for activated carbon injection. The equipment consists of storage tanks for the halogen solution, pumps and a metering system to convey the solution to the coal, and a process control system. The capital cost of installation is estimated as $3/kW.

The largest component of the operating cost for the process is the calcium bromide solution. This solution is currently available at ~ $1/lb of 52 wt% solution. It should be noted that there have been several increases in the price of calcium bromide over the last two years. Today's price is more than double the 2004 price. It is unclear if such price increases should be expected in the future. The primary consumer of calcium bromide is the oil industry, which uses it as an operational fluid for offshore oil wells.

An existing patent[8] on the use of bromine to oxidize mercury may require royalty payments to the patent holder. The amount of the royalty payment is not known at this time.

- **Technology Maturity:** Testing 5 years of experience
- **Number of Commercial Installations:** None
- **Expected Performance:**
    - Hg – An additional 10-78% above native capture, with downstream FGD system
- **Capital Costs:** 2.5-3.5 $/kW
- **Operating Costs:** 0.25-2.5 $/kW-yr. (Chemical cost only, no royalties)
- **Installation Schedule:** 6-12 months for design, installation, and parametric testing.
    - **Outage Required:** None.

A.2.7 Toxecon

Toxecon is an EPRI developed technology that involves the injection of dry sorbent, such as powdered activated carbon into a compact pulsed-jet fabric filter installed downstream of an existing primary PM control device. The Toxecon system has been demonstrated to achieve 90%+ removal of mercury from the flue gas and offers additional reduction of PM with the installation of the baghouse. In facilities that do not currently operate an FGD scrubber, Toxecon may be coupled with alkali injection upstream of the fabric filter to achieve acid gas control, for reduction of HCl, HF, and SO_2. In general, this technology may be an attractive control option for facilities operating a hot-side ESP with no FGD system.

A generic process flow diagram of the system is shown in Figure A-4. A new pulsed-jet fabric filter is installed downstream of an existing PM control device, and a pneumatic conveying system and storage silo are included for sorbent injection. If additional alkali injection is included, a second storage silo and transport system will be required. Note that the capital cost of the DOE demonstration project at Wisconsin Energy's Presque Isle Power Plant in Michigan was $52.9MM treating approximately 270 MWe, indicating a capital cost of over $190/kW. However, costs for this demonstration project were likely inflated due to the nature of the demonstration/first-of-its-kind installation. Additionally, a capital cost saving configuration of Toxecon may be employed whereby the last fields of the ESP are converted to a fabric filter PM collector (Toxecon 1.5). In this case, the sorbent injection point would be just downstream of the ESP fields, and upstream of the converted fields. Elimination of the new fabric filter housing from the system configuration would be expected to reduce the capital costs by 50-60% in comparison with the full Toxecon system.

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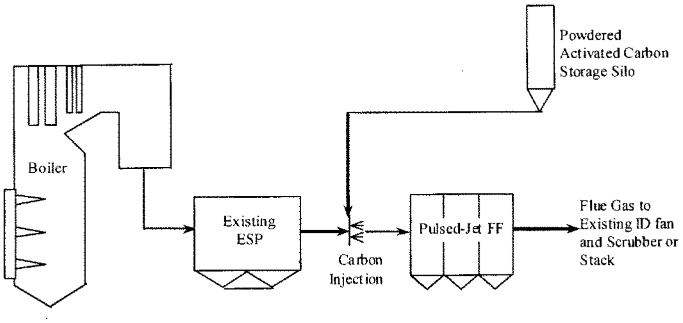
[8] Vosteen, B. US Patent 6878358.

Figure A-4. Toxecon System


Powdered Activated Carbon Storage Silo
Boiler
Existing ESP
Carbon Injection
Pulsed-Jet FF
Flue Gas to Existing ID fan and Scrubber or Stack

Operating costs of the Toxecon system include costs for powdered activated carbon, power associated with additional pressure drop across the fabric filter, solids disposal, and fabric filter maintenance, including bag filter replacement. Operating costs are estimated to be $4-6/kW-yr.

- **Technology Maturity:** Commercial demonstration completed; sorbent injection and fabric filter are proven technologies.
- **Number of Installations:** ~5
- **Expected Performance:**
  - Hg – 90%+
  - Acid Gases – up to 90% HCl, HF with alkali injection
  - SO_2 – 40-70% with alkali injection
  - Se – up to 90% with alkali injection
- **Total Project Costs:** Demonstration project cost $190/kW)
- **Operating Costs:** 4-6 $/kW-yr.
- **Installation Schedule:** 12-24 months from detailed design to start-up
  - **Outage Rrequired:** 5-10 days.

A.2.8 Wet Flue Gas Desulfurization (FGDw)

Wet flue gas desulfurization processes remove SO_2 from coal- and oil-combustion flue gas by reacting the gas with a re-circulating alkaline reagent solution or slurry. The alkaline reagent, typically a limestone or lime slurry, reacts with the incoming SO_2 in a spray tower to form calcium salts such as calcium sulfate dihydrate (gypsum) or calcium sulfite. Solid precipitation occurs in an integrated reaction tank. The produced byproduct solids are removed from the process by way of a slurry purge routed either to a solid filtration system or to a gravity settling pond. Removal of SO_2 across a wet FGD system is determined by the size and design of the scrubber unit, the gas-liquid contact properties, and the scrubber operating parameters (i.e., nature of the FGD process chemistry). High efficiency FGD scrubbers are capable of removing 95 – 99% of the SO_2 present in the gas, depending on many factors associated with unit design, operating conditions, and flue gas composition. Wet FGD systems have historically been able to achieve higher SO_2 removal levels than dry FGD systems and are generally more cost effective (than dry scrubbers) for the treatment of flue gas derived from coal containing moderate to high sulfur levels (i.e., >2%).

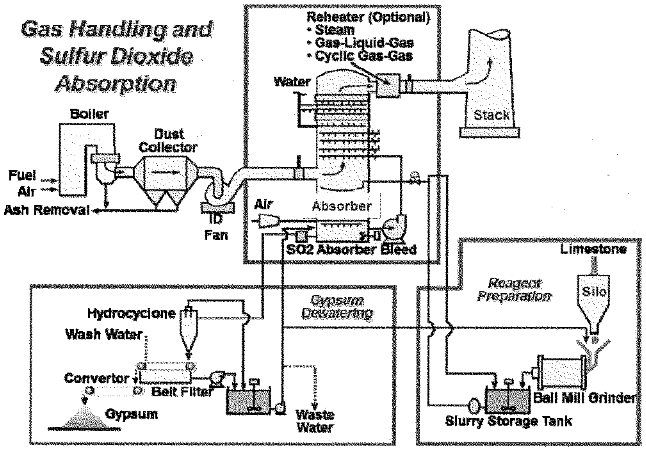
Wet FGD is a mature technology that has over 40 years of commercial operating experience in the U.S and represents greater than 80% of FGD technology installed on fossil fuel-fired power plants. The addition of wet FGD represents an appreciable cost to a utility due to high associated capital costs but the technology is technically sound and operational risks associated with the technology have decreased with continued operating experience and technology development. Although wet FGD is typically employed for SO_2 removal, it is also effective at removing acid gases, such as HCl and HF, from flue gas; wet FGD absorbers can also remove up to 50 – 70% of the particulate matter present in the gas, depending on the gas-liquid contact properties of the unit. Furthermore, evaluation of coal and process data from the EPA ICR database indicates that plants configured with wet FGD achieve high levels of selenium removal from the flue gas.

A wet FGD system may be appropriate for the removal of SO_2 and acid gases at plants that do not currently employ a scrubber system. Furthermore, the wet FGD absorber would be expected to provide additional removal (50-70%) of particulate matter penetrating the upstream electrostatic precipitator (ESP) or fabric filter (FF). Wet FGD processes are also effective at removing oxidized forms of mercury from flue gas. Thus, for bituminous coal fired plants with high flue gas mercury oxidation, particularly those employing SCR for NO_x control, high levels (70 – 90%) of mercury removal might be expected across a wet FGD system. For units firing Western sub-bituminous coal that typically produce flue gas mercury mainly in the elemental form, wet FGD provides the option for a plant to employ a mercury oxidation technology, such as boiler halogen (salt) addition, to decrease mercury emissions. For units configured with FF or Toxecon, wet FGD provides for the ability to take advantage of the natural tendency of fabric filters to oxidize mercury thus enhancing overall system removal; this effect is even greater when employing activated carbon injection upstream of the fabric filter resulting in most of the mercury that is not removed across the fabric filter getting removed across the FGD absorber.

Despite being effective at removing oxidized forms of mercury from flue gas, some wet FGD absorbers have experienced mercury re-emissions from the process. Here, mercury captured by the FGD unit is chemically reduced back to volatile elemental mercury that subsequently exits the absorber with the flue gas. Mercury re-emissions are not well understood at this time but are believed to be impacted by a number of FGD operating parameters (associated with the process chemistry). The re-emissions can be controlled using chemical additives added to the process to complex or precipitate the captured mercury.

Figure A-5 illustrates the primary components of a wet FGD process. The process can be operated under forced-, inhibited-, and natural oxidation modes. A number of reagents can be used to provide alkalinity to the process; limestone and lime represent to most common used.

Figure A-5. Illustration of Wet FGD Process; Example shows LSFO Process



For a typical limestone forced oxidation FGD process, the major cost components are associated with the following process systems:

- Flue gas handling (ductwork; bypass dampers, motive force, etc.)
- Absorber unit
- Reaction tank
- Reagent preparation
- Solids dewatering and handling
- Oxidation air
- Mist elimination
- Gas reheat (for units operating dry stacks)
- Control systems
- Wastewater treatment
- Chimney (e.g., modification from dry to wet stack)

Operating and maintenance cost categories include:

- Feed materials and chemicals
- Labor and supervision
- Waste disposal
- Maintenance, materials, and other costs
- Auxiliary power costs
- Water/water treatment costs

A wet FGD system requires a significant engineering effort and appreciable footprint at the plant site. Capital costs will be affected by the size of the boiler, type of fuel fired, required removal efficiency, solids dewatering approach, specific site arrangement, and existing equipment considerations. Capital costs for a wet FGD system can range from roughly \$300 - \$600/kW, depending on a large number of factors; additional project costs will be incurred including engineering, construction, and general facilities that are not accounted for in the above range. Fixed O&M costs can range from approximately \$9 - \$19/kW-yr, depending on the size of the unit, and variable O&M costs can range from \$15 - \$38/kW-yr. The latter is impacted by plant size and site specific factors such as delivered reagent costs, byproduct transport and disposal costs, water and wastewater costs, and auxiliary power consumption costs; these costs can be offset by revenues associated with byproduct sales.

- **Technology Maturity**: Over 40 years of commercial operation.
- **Number of Commercial Installations:** Wet FGD is installed on many plants representing roughly one-third of the coal-derived electric generation (i.e., >100 GW) in the U.S.
- **Expected Performance:**
  - SO_2: High-performance FGD scrubbers can achieve 95 – 99% SO_2 removal.
  - HCl: Most well-performing wet FGD units are able to achieve hydrogen halide removal rates equal to or greater than the respective SO_2 removal rate.
  - PM: High-efficiency FGD units can typically remove up to 50-70% of the particulate material entering the absorber in the flue gas.
  - Mercury: Wet FGD units can typically remove 85-90% of the oxidized mercury present in the incoming flue gas; elemental mercury removal is typically less than 10%. Overall mercury removal is impacted by the extent of mercury re-emissions experienced by a given absorber unit.
- **Capital Costs:**
  - \$300 - \$600/kW
- **Operating Costs:**
  - Fixed O&M costs can range from \$9 - \$19/kW-yr while variable O&M costs can range from \$15 - \$38/kW-yr.

- **Installation Schedule:**
    - Typical schedules for the design, installation, and startup of new FGDs range from 24 – 44 months.
- **Outage Required:**
    - 4 – 8 weeks.

A.2.9 Wet Electrostatic Precipitator (WESP)

Wet electrostatic precipitators (WESPs) have been used in many industries for the effective control of sulfuric acid and PM for over 100 years. However, only in the past several years has the WESP been considered practical and necessary for utility applications. WESPs have been considered and employed on the utility scale in order to reduce ultra-fine and condensable PM, including acid mist removal downstream of a wet scrubber. Although utility applications of WESP are fairly new, they have been shown to achieve high levels of SO_3 removal (> 80%) when used in combination with a wet FGD system. The collection of submicron PM is improved in the WESP over the dry ESP due to the ability of a WESP to achieve higher corona power levels, and the operation at saturation temperature, which promotes condensation of soluble acid aerosols.

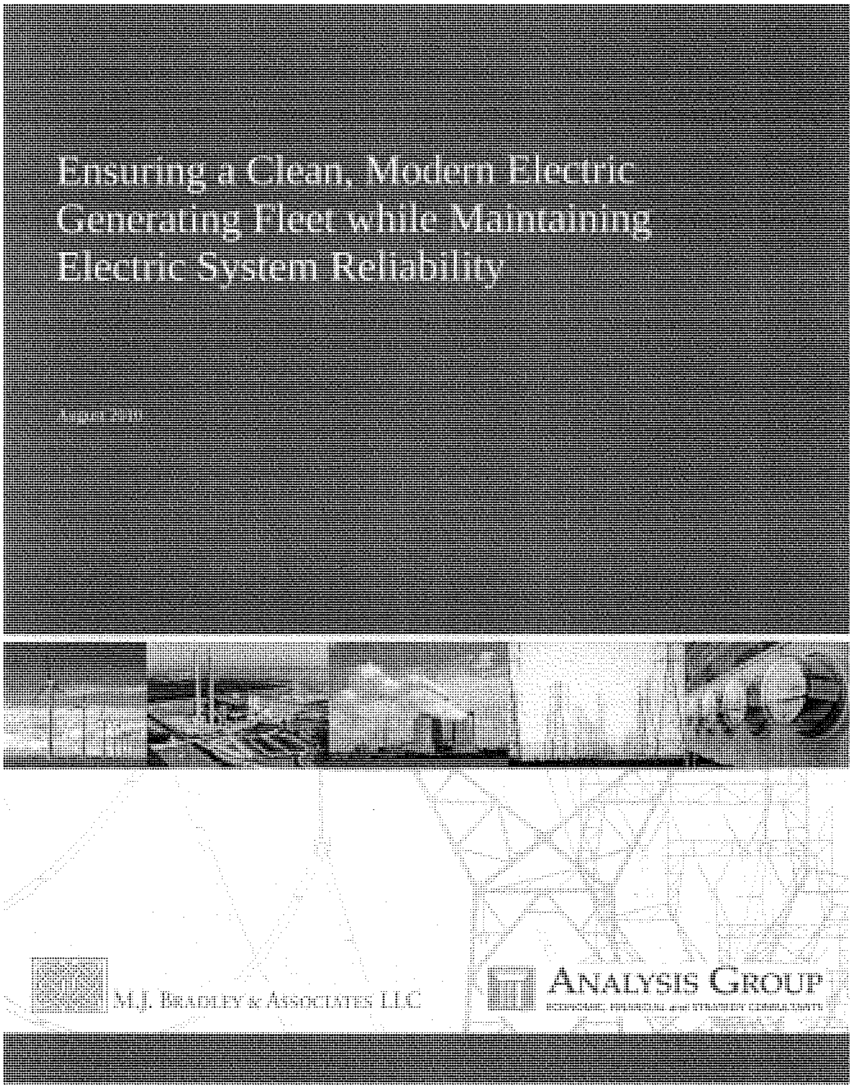
A WESP is configured much like a dry ESP, using multiple collecting and electrode fields. It is designed for large gas volumes, high PM inlet loading rates, and low outlet emissions. The parallel collecting fields are arranged in series and housed in a single enclosure. Collecting plates in a WESP are specifically designed to ensure uniform water film over the entire collecting area and an integral part of the WESP design is location of water spray nozzles to allow sufficient coverage over the collector plates. WESPs generally employ special alloys in order to avoid corrosion. One vendor has touted their membrane WESP as offering 20-30% cost savings over the conventional WESP by replacing solid sheet/tube collecting electrodes with fabric membranes that disperse water through capillary action. The membrane WESP has seen installation on non-utility applications up to approximately 185 MWe.

A WESP incurs higher capital costs than its dry counterpart, mainly due to the materials of construction required in order to avoid corrosion problems. Because the cost of the system is highly dependent on incoming flue gas and wash water content, which will vary from site-to-site, capital costs may fall in range of $75- 200/kW, depending upon unit size. As stated above, the commercial membrane WESP may potentially offer 20-30% cost savings over its traditional counterpart.

Operational costs of the WESP include pressure drop typically associated with a PM collector, energizing of the collector plates, as well as water consumption and water discharge. There are also potential water treatment costs; however they are not included in the costs presented here. In many cases the wastewater is sent to the FGD reaction tank.

- **Technology Maturity:** mature; 100+ years of operating experience on industrial applications;
- **Number of Commercial Installations:** several at the utility-scale;

- **Expected Performance**:
  - PM – 99%+
  - HCl – not quantified; 90% expected
  - Hg – potentially 95% with wet scrubber
- **Capital Costs:** $75-200/kW, dependent upon unit size and configuration
- **Operating Costs:** $3-4/kW-yr.
- **Installation Schedule:** 12-24 months from detailed design to start-up
  - **Outage Required:** 5-10 days.



Ensuring a Clean, Modern Electric Generating Fleet while Maintaining Electric System Reliability

August 2010

M.J. Bradley & Associates LLC

Analysis Group

Economic, Financial and Strategy Consultants

Acknowledgements

The following report was prepared on behalf of the Clean Energy Group's Clean Air Policy Initiative, a coalition of electric companies dedicated to responsible energy and environmental stewardship. The participating companies (listed below) are some of the nation's largest generators of electricity, with over 170,000 megawatts of electric generating capacity (including 110,000 megawatts of fossil generating capacity) throughout the U.S., and serve nearly a fifth of all U.S. electric customers.

Calpine Corporation
Constellation Energy
Entergy Corporation
Exelon Corporation
NextEra Energy
National Grid
PG&E Corporation
Public Service Enterprise Group

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Executive Summary

In the 20 years since the Clean Air Act ("CAA") Amendments of 1990, electric power companies throughout the United States have deployed a wide range of pollution-control technologies, new power plants with relatively low emissions, and demand-side measures to reduce air emissions from electricity production. The Environmental Protection Agency ("EPA") has found, however, that despite this significant progress in reducing emissions, in 2008 about 127 million Americans still lived in counties with unhealthy air—many of which are located along the Ohio River Valley, in the Middle Atlantic, and in the Southeast.[1,2]

To begin to address these issues, on August 2, 2010, EPA published its draft Clean Air Transport Rule (the "Transport Rule"), regulating emissions in 31 Eastern states and the District of Columbia where controlling emissions will produce the greatest public health benefit.[3] EPA plans to implement the Transport Rule on January 1, 2012. Additional rulemakings are also underway to regulate hazardous air pollutants ("HAPs"), with EPA under court order to promulgate its final "Utility MACT" rule by November 2011. According to EPA, compliance would be required by early 2015.[4]

These new rules regulating air emissions from fossil fuel-fired power plants will require certain uncontrolled plants to install pollution control equipment. Third-party analysts have concluded that some coal plant owners may choose to retire units in lieu of such installations. For example, two recent studies suggested that between now and 2015, the combination of low energy prices and EPA air regulations could result in the retirements of between 25 to 40 gigawatts ("GW")[5,6] of the nation's 1,030 GW of electric generating capacity.[7]

Although some of the nation's less efficient power plants may be retired, many existing coal plants will be retrofit with new pollution controls. Approximately half of the nation's coal-fired generating capacity (150 GW) has already installed SO_2 scrubbers, another 55 GW plan to install scrubbers, and a significant number of coal units have already announced plans to retire,[8] leaving approximately one-fourth of the nation's coal-fired generation to add pollution controls, switch to a cleaner fuel, or retire. Companies may also have the option to purchase allowances or adjust dispatch to comply with certain rules.

Some in the industry have raised concerns about the combined effects over the next five years of anticipated power plant retirements and outages required to install new pollution control equipment. Clearly, the nation must carefully consider how to maintain electric system reliability, while also improving our nation's health and environmental quality.

In this paper, we highlight the impact of EPA's upcoming air regulations, with a focus on the issue of possible power plant retirements on electric reliability. We conclude that, without threatening electric reliability, the

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[1] U.S. EPA, *Draft FY 2011-2015 EPA Strategic Plan*, at p. 7. Collectively, power plants are responsible for 66 percent of SO_2 emissions, 19 percent of NOx emissions, and 39 percent of CO_2 emissions in the U.S. Also, in 2002, the EPA cataloged emissions in the United States and concluded that fossil-fuel-fired power plants were responsible for the following percentages of nationwide emissions for the following HAPs (all figures are approximate): hydrochloric acid (60%); mercury compounds (45%); arsenic compounds (35%); and nickel compounds (25%). U.S. EPA, *2002 National Emissions Inventory Booklet*.

[2] According to the recent National Academy of Sciences, *Hidden Costs of Energy: Unpriced Consequences of Energy Production and Use* (2010), "after ranking all the [power] plants according to their damages, we found that the most damaging 10% of plants produced 43% of aggregate air-pollution damages from all plants, and the least damaging 50% of the plants produce less than 12% of aggregate damages" ...(and) the most damaging 10%...account for approximately one quarter of electricity generated at the 406 plants." (at p. 88).

[3] Office of Air and Radiation, U.S. EPA, *Air Transport Rule Factsheet*, at p. 1.

[4] U.S. EPA, *Proposed Rule: Federal Implementation Plans To Reduce Interstate Transport of Fine Particulate Matter and Ozone*. August 2, 2010.

[5] PIRA Energy Group ("PIRA"), *EPA's upcoming MACT; Strict Non-Hg Can Have Far-Reaching Market Impacts*, April 8, 2010.

[6] ICF International, *EEI Preliminary Reference Case and Scenario Results*. May 21, 2010.

[7] Energy Information Administration ("EIA"), *Electric Power Monthly*, July 2010. (Based on preliminary 2009 capacity, capacity additions and retirements up through April 2010.)

[8] PIRA, *supra* n.5.

industry is well-positioned to respond to EPA's proposed road map to "help millions of Americans breathe easier, live healthier,"[9] provided that EPA, the industry and other agencies take practical steps to plan for the implementation of these regulations and adopt appropriate regulatory approaches. In particular, we conclude the following:

1. **Even though some units likely will retire in lieu of complying with the new regulations, electric system reliability will not be compromised if the industry and its regulators proactively manage the transition to a cleaner, more efficient generation fleet.**
    - Power system reliability relates not only to generation capacity and availability, but also to consumption levels and patterns, and transmission capacity and use. As such, all these factors must be considered when assessing reliability impacts. Existing power system capacity well in excess of minimum reserve levels, relatively modest projections of load growth over the next several years, a large amount of proposed generating resources, and the availability of load management practices indicate the system can handle the level of projected retirements.
    - Each North American Electric Reliability Corporation ("NERC") reliability region has excess capacity, totaling over 100 GW of excess capacity nationwide. Therefore, considering only the projected level of coal unit attrition relative to existing capacity resources, it appears there will be no capacity shortages even if projected retirement scenarios prove accurate.
    - Further, economic conditions have reduced the demand for electricity in recent years providing an additional capacity cushion to assist in managing any power plant outages required to install pollution controls.
    - The industry has a proven track record of adding new generating capacity and transmission solutions when and where needed and of coordinating effectively to address reliability concerns. In the three years between 2001 and 2003, the electric industry built over 160 GW of new generation—about four times what analysts project will retire over the next five years.
    - Notably, many of the regions of the country with organized wholesale markets, including many parts of the Midwest, Mid-Atlantic, and Northeast, have developed effective tools such as capacity markets and reserve sharing mechanisms enabling electric generators to access other companies' available resources to assure regional reliability.
    - Additionally, the industry is deploying enhanced demand response actions, expanded energy efficiency programs, and new "smart grid" advances to manage consumption during the transition to cleaner, more efficient generation.
2. **Industry data counter concerns that it will cost the industry too much to comply with EPA's proposed air regulations, that pollution controls cannot be installed soon enough, or that the EPA regulations will lead to the closure of otherwise economically healthy power plants.**
    - The proven technologies for controlling air pollution emissions, such as NO_x, SO_2, mercury and acid gases, are commercially available and have already been, or soon will be, installed on the majority of the nation's coal plants (65 percent with scrubbers; 50 percent with advanced NO_x controls), demonstrating that the costs can be managed.
    - The industry has a demonstrated ability to schedule and sequence unit outages in an efficient and reliable manner and is capable of installing additional pollution control systems to comply with the Transport Rule and Utility MACT Rule.

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[9] U.S. EPA, *supra* n.1, at p. 2.

- Many of the coal units that are the most likely candidates to shut down are smaller, 40 to 60 year old units, which are nearing the end of their design life expectancy and are already economically challenged.

- Additionally, the retirement of some existing generating capacity will create room on the transmission grid to accommodate additional power flows, or new generating capacity, without requiring attendant upgrades in transmission, thus mitigating reliability concerns while reducing the cost of transitioning to a cleaner, more efficient generation fleet.

3. **EPA, the Federal Energy Regulatory Commission ("FERC"), the Department of Energy ("DOE") and State utility regulators, both together and separately, have an array of tools to moderate impacts on the electric industry.**

   - EPA may, and if needed, should exercise its statutory authority under the CAA to grant, on a case-by-case basis, extensions of time to complete pollution control installations where appropriate.

   - To the extent that its legal authority allows, EPA should adopt regulatory approaches that allow for cost-effective compliance, such as the emissions trading mechanism proposed in the Transport Rule.

   - In circumstances in which power plant retirements trigger localized reliability concerns, EPA and DOE should follow established precedent, including use of consent decrees, to permit continued operation for reliability purposes only, pending necessary upgrades or generation additions. Additionally, the various federal agencies and offices with responsibility for assuring reliability for the nation's electricity capability should work together to help support the industry and states in complying with EPA's new air regulations.

   - Transparent, well-established market rules approved by FERC and overseen by independent market monitors, particularly the forward capacity markets relied on by some Regional Transmission Operators ("RTOs"), as well as state regulatory agency oversight, provide additional safety nets to help ensure adequate capacity.

   - Although EPA is under court order to promulgate its air regulations, the Agency can and should coordinate the implementation of anticipated water regulations under Section 316(b) of the Clean Water Act ("CWA") and new waste regulations to avoid possible reliability concerns.[10]

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[10] EPA should also consider the possible greenhouse gas emissions implications of its 316(b) regulations. In 2007, the U.S. Supreme Court found the EPA has clear statutory authority to regulate greenhouse gases under the CAA. Transitioning to a cleaner generating fleet will help EPA fulfill this obligation.

I. MANAGING ELECTRIC SYSTEM RELIABILITY WHILE IMPLEMENTING NEEDED ENVIRONMENTAL IMPROVEMENTS WITH SIGNIFICANT PUBLIC HEALTH BENEFITS

A. The Electric System Has Substantial Excess Generating Capacity and Appropriate Processes in Place to Assure Reliable Electricity Supply to Consumers

Currently, there are more than 17,000 electric generation units in the United States with a combined nameplate capacity of over 1,030 GW.[11] In 2009, coal-fired generation produced 45 percent of the nation's electricity, followed by natural gas (23 percent) and nuclear (20 percent), with the remaining amount produced through a combination of hydroelectric power, oil, wind and other miscellaneous fuel types.[12]

Power plant owners, transmission system owners, and power system operators plan and operate their systems according to numerous federal, state and local regulations, policies and protocols, applying planning requirements designed to ensure electricity suppliers have adequate resources to meet current and future demand, and operational standards to ensure power is available when consumers turn on the lights.

Power system reliability is tied to many things: generation plant capacity and availability, consumption levels and patterns, and transmission capacity and use. As such, electric system planners must consider all of these relevant system infrastructure and demand factors in assessing whether sufficient capacity will be available to maintain reliability. Existing power system capacity well in excess of minimum reserve levels, relatively modest projections of load growth over the next several years, a large amount of proposed generating resources throughout the country, and the availability of load management practices indicate the electric system should be able to handle the transition to a cleaner, more efficient generation fleet.

Under FERC's oversight, NERC sets standards to ensure the reliability of the nation's electric system. NERC comprises eight regional reliability organizations (or "regions," as shown in Figure 1), whose members include grid operators, utilities, generating companies and others in the electric industry.

Most of the nation's regional reliability organizations cover multiple states and each manages and monitors compliance with NERC's reliability standards, including maintenance of minimum target reserve margins, a key indicator of resource adequacy. Actual or expected reserve margins measure the extent to which generating capacity exceeds (or falls short of) peak electricity demand. All regions must have capacity above expected demand to accommodate power plant outages, transmission failures, unexpectedly high demand, or other contingencies. Most regions have a minimum target reserve margin at or below 15 percent.[13] In recent years, actual reserve margins around the country have been well above the minimum target levels, due not only to new power plant additions in most regions, but also to reduced demand attributable to the economic recession and increasingly robust load management programs.[14]

Table 2 illustrates that, in 2013, all NERC regions expect to have actual capacity levels well in excess of minimum reserve requirements. Although this provides only one metric of reliability, and each region will undertake more granular analysis in the months ahead, these capacity "cushions" indicate there should not be a capacity shortage even if projected retirement scenarios prove accurate. As the table further highlights, on an aggregate basis across all NERC regions, the electric sector is expected to have over 100 GW of surplus generating capacity in 2013, about three times the 30 to 40 GW of retirements projected by PIRA Energy Group.[15,16] Reliability First Corporation ("RFC") and the Southeast Reliability Corporation

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[11] EIA, *supra* n.7.

[12] EIA, *Net Generation by Energy Source*, http://www.eia.doe.gov/cneaf/electricity/epm/table1_1.html (accessed July 31, 2010).

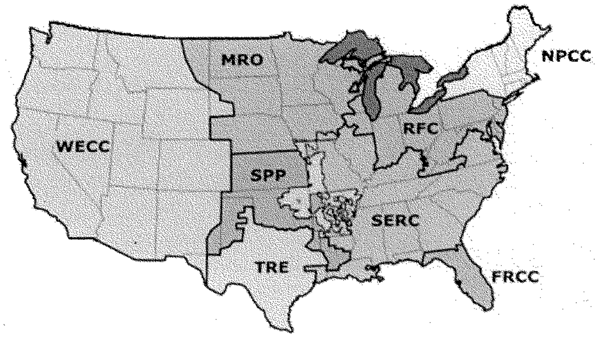
[13] Some regions are below 15%, such as TRE (12.5%), SPP (13.6%), WECC (14.7%). Regions that don't establish a formal target are assigned one for planning purposes by NERC, with 15% for regions like the Midwest and 10% for regions with substantial hydroelectric power. NERC, *2010 Summer Reliability Assessment*, May 2010.

[14] *Id.*

[15] NERC, *2009 Long-Term Reliability Assessment: 2009-2018*, October 2009.

("SERC") regions, for example, where most of the uncontrolled coal plants are located, are expected to have high reserve margins at 24.3 percent and 26.3 percent, respectively.[17] These regions could retire 17.1 GW (RFC) and 23.9 GW (SERC) of capacity and still maintain the 15 percent NERC reserve margin target.

Figure /Table 1 - NERC Electric Reliability Regions



FRCC – Florida Reliability Coordinating Council	SERC – Southeast Reliability Corporation
MRO – Midwest Reliability Organization	SPP – Southwest Power Pool, RE
NPCC – Northeast Power Coordinating Council	TRE – Texas Regional Entity
RFC – Reliability First Corporation	WECC – Western Electricity Coordinating Council
Note: NERC regional results shown in this presentation include the continental US only	

Table 2 - Estimated Reserve Margins in All NERC Regions: Adequate Generating Capacity

NERC Electric Reliability Region	Projected Reserve Margin[1] in 2013	Cushion Above NERC Target Reserve Margin[2] in 2013
TRE	21.5%	7.8 GW
FRCC	28.6%	6.1 GW
MRO	22.1%	5.2 GW
NPCC	24.4%	3.9 GW
RFC	24.3%	17.1 GW
SERC	26.3%	23.9 GW
SPP	30.3%	7.7 GW
WECC	42.6%	35.6 GW
Total		**107.3 GW**

[1] Includes capacity defined by NERC as Adjusted Potential Reserve Margin, which is the sum of deliverable capacity resources, existing resources, confidence factor adjusted future resources and conceptual resources, and net provisional transactions minus all derates and net internal demand expressed as a percent of net internal demand. Source: NERC, *2009 Long-Term Reliability Assessment: 2009-2018*, October 2009, p. 396 (Summer Demand).

[2] Capacity in excess of what is required to maintain NERC Reference Margin or the regional target reserve levels.

Source: NERC, 2009 Long-Term Reliability Assessment: 2009-2018, October 2009.

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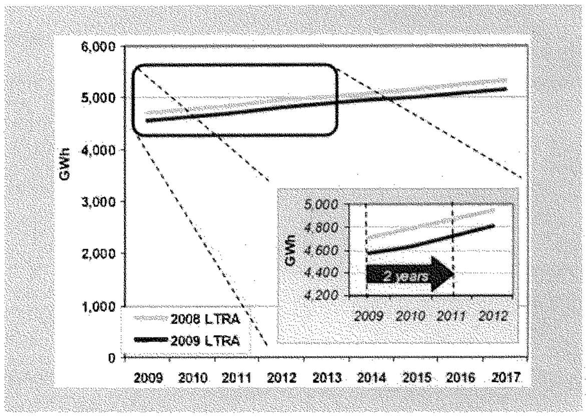
[16] PIRA, *supra* n.5.

[17] NERC, *supra* n.15.

Experience in the RFC region, which encompasses thirteen states in the Midwest and Mid-Atlantic regions, is illustrative of the electric system's ability to tolerate retirements without jeopardizing reliability. Generators in the PJM Interconnection ("PJM") retired about 6,000 MW of capacity between 2004 and 2007, and over 3,000 additional MW of capacity have been announced for retirement in PJM by 2012.[18] Despite almost 10,000 MW of retirements over this seven year period, the RFC region is still forecast to have a reserve margin of over 24 percent in 2013, or an excess of 17,000 MW of generation above the 15 percent NERC target reserve margin target.

Moreover, as a result of the economic recession, NERC projects "significant reductions in projected long-term energy use in North America" [19], which provide an additional capacity cushion. While total demand is still projected to increase in most regions, it will do so at a slower pace and from a lower starting point. See, for example, Figure 2 which shows the decrease in forecast energy use from NERC's 2009 long-term reliability assessment as compared to its 2008 forecast. Additionally, summer peak demand has decreased over 10 GW per year for two consecutive years.[20] Furthermore, in all regions of the country, well-established tools exist to analyze potential regional power system impacts, and to facilitate planning, managing and operating the system to ensure ongoing reliability.

Figure 2 – Annual Energy Use (2008 LTRA and 2009 LTRA Forecast Comparison)



Source: NERC, 2009 Long-Term Reliability Assessment: 2009-2018, October 2009, p. 13.

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[18] PJM, *Generation Retirement Summaries*, http://www.pjm.com/planning/generation-retirements/gr-summaries.aspx (accessed July 31, 2010).

[19] NERC, *supra* n.15, at p. 13.

[20] NERC, *supra* n.13, at p. 1.

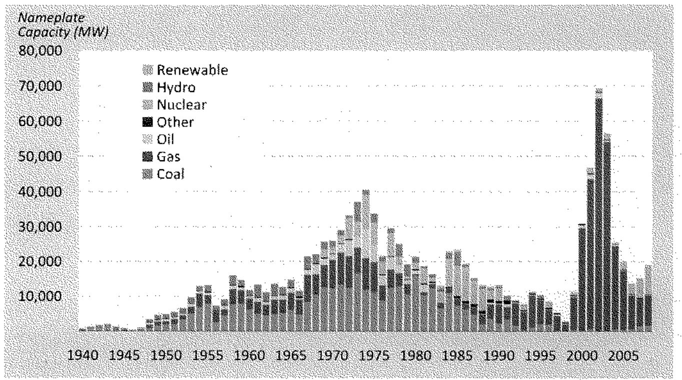
B. The Electric Industry Has Proven Its Ability to Avoid Capacity Problems in the Past—Through Power Plant Capacity Additions, Fuel Conversions, Transmission Solutions, and Load Management Techniques

1. New Capacity is Already in the Pipeline

Even with the robust reserve margins in all NERC regions, industry participants are pursuing various measures to safely and reliably transition to cleaner, more efficient electric supply resources. Plans are underway for a variety of new plants, even as less efficient ones are retired. While economics remains the major consideration in deciding whether to develop or expand generating capacity or to mothball older plants, other major drivers, including reliability and environmental improvements, are in play. For example, the implementation of forward capacity markets in certain Independent System Operators (ISOs) has provided more price transparency, enabling the industry to see the value of various generation resources.

Moreover, the industry has shown previously that it can efficiently add capacity or respond adequately to potential reliability issues. Between 1999 and 2008, for example, in response to a variety of market, regulatory and economic signals, the electric sector added almost 270 GW of natural gas-fired generating capacity, the equivalent of more than 80 percent of the entire existing U.S. coal fleet.[21] (See Figure 3, which shows the significant investment in new gas plants during the past decade.) Indeed, in just three years between 2001 and 2003, the electric industry built over 160 GW of new generation,[22] about four times what analysts project will retire over the next five years. Although conditions a decade ago differ in several respects, this robust construction cycle suggests that developers and investors will respond to strong signals if new capacity is needed.

Figure 3 – Power Plant Capacity Added by Year It Entered Service



Source: Ceres, et al., Benchmarking Air Emissions of the 100 Largest Electric Power Producers in the United States, June 2010.

Further, as indicated in Table 3, substantial new capacity build has been announced, planned or is seeking grid interconnection studies. Across the NERC regions, a recent report identified over 55 GW of proposed generation in advanced stages of development in the queue for 2013. Although, not all of these plants will be built, strong market incentives and signals from regulators that new capacity will be needed will promote generation development proposals beyond those announced to date.

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[21] EIA, *Annual Electric Generator Report: Form EIA-860*, 2008.
[22] *Id.*

Table 3 - Proposed New Build – 2013[23]

NERC Region	New Generation Proposed to Be Built, by Transmission Planners for 2013
TRE	4.3 GW
FRCC	2.0 GW
MRO	3.4 GW
NPCC	7.5 GW
RFC	8.7 GW
SERC	18.3 GW
SPP	2.4 GW
WECC	16.3 GW
Total	55.5 GW

Note: There are substantial additional generating facilities in the queue in each region.

Numerous electric companies have already announced substantial new capacity additions, many at the sites of existing coal units that will be retired. Georgia Power, which recently demolished a coal plant in Georgia and stated its intention to retire another, announced it plans to build three 840 MW combined cycle gas turbines ("CCGTs") in Georgia.[24] Oglethorpe Power Corporation has proposed a 605 MW CCGT[25] and a 100 MW biomass facility in Georgia.[26] Also in the Southeast, Progress Energy plans to build a 950 MW CCGT at the site of three coal units, which will retire when the gas plant comes online.[27] In Tennessee, TVA is building an 878 MW CCGT at the site of its John Sevier coal plant, and the City of Vineland New Jersey plans to replace its 25 MW coal plant with a 60 MW gas plant.[28,29]

Also, altbougb they do not operate in the same base load mode as do nuclear or many coal plants, low emission energy facilities have expanded rapidly over the past several years.[30] For example, the total wind power capacity now operating in the U.S. is over 35,600 MW. In 2009 alone, the U.S. wind industry broke all previous records by installing nearly 10,000 MW of new generating capacity, enough to serve over 2.4 million homes. Additionally, over 400 MW of solar was installed throughout the nation in 2009. Solar installations are poised to grow about 50 percent annually in the next three years, reaching 1.5 GW to 2 GW of new installations in 2012.[31]

The retirement of inefficient coal units may spur further development of cleaner generating capacity. Regional transmission studies include capacity even if it runs infrequently. Freeing room for new capacity through retirements means some low emission generation resources, including gas plants, can be accommodated without having to invest in new transmission.

2. Existing Gas Units Have Untapped Power Production Potential

Given the significant addition of gas-fired capacity in the past decade, as detailed earlier in Figure 3, and the relative price advantage of coal versus natural gas in the period from 2007 to 2008, gas plants were not operated at their full design capability in many parts of the country. As detailed in Table 4, gas-fired CCGT power plants in 2008 had an average utilization rate of only 33 percent, as compared to coal's 56 percent.

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[23] ICF International, *supra* n.6.
[24] Georgia Power, *From Coal to Natural Gas*, http://www.georgiapower.com/generation/home.asp (accessed July 31, 2010).
[25] Oglethorpe Power, *Oglethorpe Power to Build Gas-Fired Generating Plant*, March 10, 2010.
[26] Power-Gen Worldwide, *Oglethorpe plans a biomass plant*, June 29, 2010.
[27] Energy Business Review, *Progress Energy Wins Approval To Build 950MW Gas-fired Plant*, October 2, 2009.
[28] Marketwire, *TVA Prepares to Begin Construction on 880-Megawatt Combined-Cycle Unit*, March 16, 2010.
[29] NJ Spotlight, *NJ Coal Plants Face Cleanups and Closures*, July 10, 2010.
[30] Wind and solar are intermittent resources; therefore, only part of their output is credited for reliability purposes.
[31] GTM Research, *The United States PV Market Through 2013: Project Economics, Policy, Demand and Strategy*, December 2009.

Despite declines in natural gas prices, existing gas units have significant untapped power production potential, which can be expanded during off peak periods without constructing new generation. This excess capacity can assist in managing power plant outages required to install pollution control systems.

Table 4 – Estimated Utilization of U.S. Coal and Gas Plants (CCGT) by Region (2008)

Region	Plant Size (MW)	Coal		Gas (Combined Cycle)	
		Total Installed Capacity (MW)	% Utilization	Total Installed Capacity (MW)	% Utilization
FRCC	>500	7,981	67%	17,678	46%
	200 – 500	1,628	64%	2,410	26%
	< 200	199	53%	1,389	20%
MRO	> 500	18,113	73%	3,033	15%
	200 - 500	4,915	59%	1,246	15%
	< 200	3,111	42%	506	10%
NPCC	> 500	2,407	79%	13,791	44%
	200 - 500	2,548	70%	4,326	36%
	< 200	1,079	47%	2,843	21%
RFC	> 500	99,474	61%	28,087	19%
	200 - 500	11,479	54%	2,709	13%
	< 200	4,664	48%	1,794	34%
SERC	> 500	91,188	66%	40,529	24%
	200 - 500	10,699	57%	4,995	29%
	< 200	4,109	36%	1,229	33%
SPP	> 500	17,970	71%	12,051	32%
	200 - 500	2,361	72%	2,116	37%
	< 200	647	44%	465	22%
TRE	> 500	15,193	80%	28,869	44%
	200 - 500	1,213	82%	5,025	36%
	< 200			1,020	24%
WECC	> 500	30,081	73%	37,435	47%
	200 - 500	2,992	78%	6,835	40%
	< 200	2,465	60%	5,042	49%
All US Plants	**> 500**	**282,407**	**67%**	**181,473**	**35%**
	200 - 500	**38,277**	**60%**	**30,136**	**32%**
	< 200	**16,616**	**45%**	**15,966**	**30%**

Source: MJB&A analysis based on U.S. Energy Information Administration's Form EIA-860 (2008) and EIA-923 (2008)

Additionally, many coal plants have the potential to repower their units, by replacing conventional coal-fired steam electric generating units with CCGTs, thus increasing the units' efficiency *and* reducing air emissions—an approach already being used today by the industry. For example, Xcel Energy has replaced a 270 MW coal plant in Saint Paul, Minnesota with a 515 MW CCGT, reducing SO_2 emissions by 99.7 percent, NOx emissions by 96.9 percent, and eliminating mercury emissions.[32] It also repowered two coal units in Minneapolis.[33] In New Jersey, Calpine has announced its intent to convert an 83 MW coal unit to a 158 MW gas unit.[34]

3. Enhanced Load Management Programs Can Be Deployed to Meet System Reliability Needs Economically

Historically, grid operators have dispatched plants to meet customers' electricity requirements. Over the years, the industry has recognized that decreasing load requirements can be more efficient and economical than increasing supply by dispatching generation. As a result, load management tools, such as demand response ("DR") and energy efficiency ("EE") programs have been widely implemented across the nation.

DR programs manage load by temporarily reducing or shifting electricity use by homes or businesses during critical times like hot summer days. EE programs, on the other hand, primarily seek to reduce consumers' energy use on a permanent basis through the installation of energy efficient technologies and conservation measures. Both means of load management provide an additional tool for system operators to manage electric reliability.

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[32] Utility Engineering, *Twin Cities to breathe easier thanks to UE*, Value Connection, Issue 2, 2007.

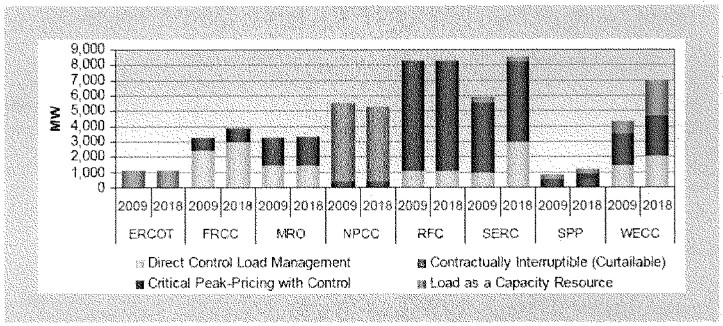
[33] North Dakota Home Town Times, *Xcel Energy Switches Minneapolis Coal Plant to Natural Gas*, October 13, 2009.

[34] NJ Spotlight, *supra* n.29.

DR programs operate in all of the NERC Regions, as shown in Figure 4. In some regions, such as RFC, SERC, WECC, and MRO, a substantial fraction of the DR resources are available in the form of "contractually interruptible" or curtailable loads. These typically entail contracts between a utility and an industrial customer, in which the customer agrees to curtail part of its usage when requested for a specified number of times during a certain period, in exchange for electric rate discounts. The other forms of DR—direct control load management, critical peak pricing with control, and load as a capacity resource—are more dynamic forms of supply, in which the grid operator, in effect, dispatches the load to respond with a reduction or shift in load, much like a generating facility.

In particular, these other forms of DR have increased steadily in organized wholesale competitive markets. In PJM, for example, DR has increased five-fold in the past five years and continues to grow.[35] In the most recent PJM capacity auction, DR offers increased 32 percent over last year and over 9,000 MW cleared, which represents about six percent of total available capacity resources.[36] DR is expected to reduce the peak electricity use this summer in PJM by 8,525 MW, the equivalent output of ten large power plants.[37]

Figure 4 – NERC Summer Peak Capacity Demand Response - 2009-2018 Comparison



Source: NERC, Long-Term Reliability Assessment, 2009, Figure 7 (page 18).

DR is not just increasing in PJM. According to the ISO/RTO Council, competitive markets are "shattering barriers" in terms of attracting DR resources.[38] In FERC's recently released *National Action Plan on Demand Response*, it highlighted that DR has tripled in recent years in the New England region[39] and identified strategies to further enhance DR. Already, about half of electric utilities across the nation have some type of DR program. With continued support from regulatory agencies like FERC and the advancement of "smart grid" technologies, DR is expected to continue to grow as a viable supply alternative to traditional generation.

As with DR, EE programs have increased dramatically in the past several years. According to information compiled by the Consortium for Energy Efficiency, and as highlighted in Figure 5, the total budget for all US ratepayer-funded EE and DR programs has increased 80 percent since 2006 to $4.4 billion in 2009.[40] These programs resulted in savings of almost 105,000 gigawatt hours ("GWh") of electricity in 2008—the equivalent of the total electricity consumption in Tennessee in the same year.[41] By 2018, new EE programs alone are expected to reduce summer peak demands by almost 20,000 MW (a full year's growth).[42]

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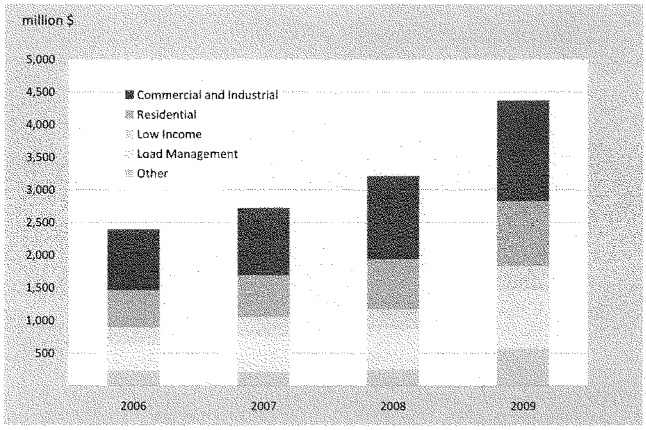
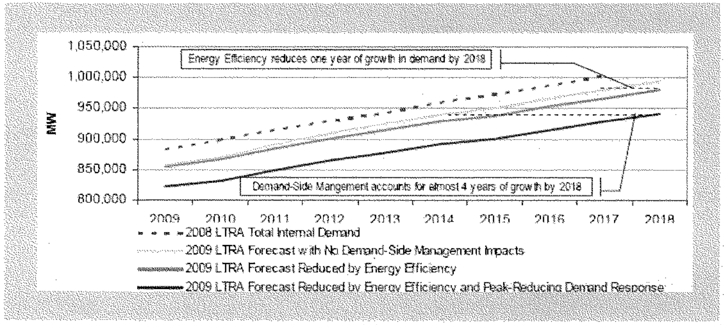
[35] PJM, *Demand Response To Play Significant Role In Meeting PJM's Higher Summer Peak Electricity Use*, http://pjm.com/~/media/about-pjm/newsroom/2010-releases/20100505-summer-2010-outlook.ashx (accessed August 6, 2010)
[36] PJM, *2013/2014 RPM Base Residual Auction Results*, at p. 1.
[37] PJM, *supra* n.35.
[38] ISO/RTO Council, *2009 State of the Markets Report*, September 22, 2009.
[39] The Federal Energy Regulatory Commission Staff, *National Action Plan on Demand Response*, June 17, 2010, at p. 7.
[40] Consortium for Energy Efficiency ("CEE"), *The State of the Efficiency Program Industry: Budgets, Expenditures, and Impacts*, 2009, at p. 7.

Figure 5 – Energy Efficiency and Demand Response Program Budgets, 2006-2009



Source: Consortium for Energy Efficiency, The State of the Efficiency Program Industry: Budgets, Expenditures, and Impacts, 2009

Figure 6 – Summer Peak Demand Growth Reduced by Demand-Side Management



Source: NERC, Long-Term Reliability Assessment, 2009, at p. 18.

Although California and the Northeast account for over half of the total, budgets for ratepayer-funded EE programs are expanding in all regions of the country. In 2009, EE budgets for Illinois, Wisconsin, and Iowa increased in 2009, year-on-year, by 60 percent, 40 percent, and 36 percent, respectively.[43] In the Southeast, Alabama, Mississippi, North Carolina, and Louisiana reported ratepayer-funded EE budgets for the first time in 2009.[44] EE's use as a capacity resource is increasing in organized wholesale markets as well. For example, EE resources accounted for 757 MW of the resources offered into the most recent PJM RPM auction, an increase of 33 percent over the prior year. Of those resources, 90 percent, or 680 MW cleared the auction to serve as a firm capacity resource.[45]

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[41] *Id.*
[42] NERC, *supra* n.15, at p. 12.
[43] CEE, *supra* n.40, at p. 15.

NERC estimates that current levels of EE and DR will shave off certain portions of expected growth in demand, as shown in Figure 6, underscoring growing acceptance of these load-management tools.

Based on the experience of states and organized competitive wholesale markets that have implemented EE and DR, it is clear these programs provide yet another cost-effective tool to help maintain reliability in the face of generation retirements.

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[44] *Id.* at p. 16.

[45] PJM, *supra* n.36.

II. The Industry Has The Capacity To Timely Respond To EPA's Future Air Regulations

A. The Majority Of Coal Plants Have Already Installed Air Pollution Controls

Proven pollution control technologies are widely available to dramatically reduce emissions of NO_x, SO_2, mercury, and other HAPs from coal plants, which account for 98 percent of the electric sector's SO_2 emissions, 86 percent of its NOx emissions, and 98 percent of its mercury emissions.[46,47]

Over the last 20 years, the industry has deployed a number of different technologies to comply with federal and state SO_2 and NOx regulations. The three basic options for reducing SO_2 emissions from coal plants include: (1) switching from higher to lower sulfur coal; (2) blending higher sulfur coal with lower sulfur coal; or (3) installing flue gas desulfurization ("FGD") control systems, commonly referred to as scrubbers. Wet scrubbers, which use a sorbent to capture SO_2, can typically achieve at least 95 percent SO_2 removal. Widely available NOx control technologies for coal generation can be grouped into two broad categories: combustion modifications and post-combustion controls. Post-combustion controls can reduce NOx emissions by 90 percent or more by removing the NOx after it has been formed in the boiler. The most common post-combustion control is selective catalytic reduction ("SCR") technology, in which ammonia (NH_3) is injected, combining with the NOx in the flue gas to form nitrogen and water.

The majority of coal plants have already installed such controls. Of the 310 GW of coal capacity in the United States, 150 GW have installed FGD systems and another 55 GW have FGD controls planned,[48] representing 65 percent of the existing coal fleet. As detailed in Attachment A, numerous scrubber installations have been recently completed or soon will be completed. Additionally, about 50 percent of coal capacity in the U.S. has installed or soon will be retrofit with advanced NOx controls (SCR and selective non-catalytic reduction ("SNCR") technologies).[49]

To date, most studies put a heavy emphasis on deploying scrubbers to comply with the new EPA air regulations. Retirements occur where the costs of installing scrubbers does not make economic sense based upon the unit's characteristics. However, a number of companies have announced that they will use other less costly technologies in lieu of scrubbers. For example, on August 5, 2010, Edison Mission International, one of the nation's largest merchant coal generators, announced it could achieve compliance without installing scrubbers by using trona injection technology.[50]

B. With Proper Planning, the Industry Can Install the Necessary Pollution Controls on a Timely Basis

EPA projects that about 14 GW of additional coal-fired generating capacity will need to be retrofit with scrubbers and less than 1 GW with SCR controls by 2014 to comply with the recently proposed Transport Rule.[51] This number of retrofits is significantly less than the industry has added in past construction cycles. For example, during the peak of scrubber construction, between 2008 and 2010, approximately 60 GW of coal capacity was retrofit with scrubber controls,[52] highlighting the industry's ability to complete a

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[46] EIA, *U.S. Electric Power Industry Estimated Emissions by State (EIA-767 and EIA-906)*, Electric Power Annual 2008, http://www.eia.doe.gov/cneaf/electricity/epa/emission_state.xls (accessed July 30, 2010)

[47] U.S. EPA Office of Air Quality Planning and Standards, *National Emissions Inventory for Hazardous Air Pollutants*, 1999.

[48] PIRA, *supra* n.5, at p. 7.

[49] U.S. EPA, *National Electric Energy Data System ("NEEDS")*, version 3.02.

[50] Trona is a naturally occurring sorbent that can be injected directly into boilers to remove harmful air toxics without the use of FGD scrubbers. Given that the PIRA and EEI analyses did not consider trona and other less costly compliance options, the predicted retirement scenarios are very likely overstated. Nonetheless, this report uses the predicted retirements as a conservative input to test all of the reliability considerations.

[51] U.S. EPA, *supra* n.4.

[52] M. J. Bradley & Associates analysis based on U.S. EPA NEEDS Database v. 3.02.

substantial number of retrofits over a short period of time. In 2009 and 2010, the industry completed between 50 and 60 scrubber retrofits each year.[53]

Moreover, the industry's past successful installation of pollution controls on numerous units underscores its ability to schedule and sequence any required unit outages in an efficient and reliable manner. To help ensure reliability, generators and transmission owners provide reasonable advance notice of any planned outages to the respective transmission authorities. In turn, the transmission authorities develop a coordinated outage schedule to prevent any deliverability problems. This illustrates a key benefit of a fully integrated national transmission system.

Further, the CAA allows three years for existing sources to comply with the Utility MACT rule with the possibility of a one-year extension. EPA is under a court-imposed deadline to complete its regulations by November 2011, with compliance required by late 2014. As numerous states have adopted regulations limiting mercury emissions from coal-fired power plants, many companies have already begun to install mercury control technologies. Also, the scrubber and particulate control systems installed to comply with the Transport Rule and other EPA regulations will help companies to comply with future air toxics regulations.

In the event, however, that any required retrofit construction schedules could not be completed within the pre-compliance period, EPA may, and should, exercise its authority under Section 112(i)(3)(B) of the CAA to provide up to one-year extensions to complete pollution control installations. In addition, to protect the national security interest of maintaining adequate electrical grid reliability, the President has the authority under Section 112(i)(4) of the CAA to grant one or more compliance extensions of up to two years each. Any such extensions would be unit-specific and based on clear demonstration that the technology to implement such standards is not available.

These federal tools combined with market rules and signals, industry reliability standards and enforcement mechanisms, and utility regulatory requirements and incentives, provide a robust portfolio of techniques to assure compliance with health-based air regulations while maintaining reliable electricity supply.

C. The Coal Plants Most Likely To Retire Are Nearing The End Of Their Design Life Expectancies And Are Already Economically Challenged

As indicated by Table 5, many of the uncontrolled coal units, which are the most likely to retire, are smaller (250 MW and below) and are 40 to 60 years old. Thus, the coal plants most likely to retire are already nearing the end of their design life expectancies, as confirmed in recent coal plant retirement announcements, detailed in Attachment B.

Table 5 - Characteristics of U.S. Coal Plants

Unit Age	Units		Capacity		Avg. Unit Size (MW)	Pollution Control Installed (% of units)			
	Count	%	MW	%		SNCR	SCR	Scrubber	Uncontrolled
> 60 years	46	5%	1,782	1%	39	2%	4%	13%	87%
51 - 60 years	313	32%	40,787	13%	127	11%	9%	19%	64%
41 - 50 years	233	23%	58,078	20%	249	15%	19%	31%	53%
31 - 40 years	228	23%	114,890	38%	498	4%	43%	63%	27%
21 - 30 years	164	16%	80,155	27%	492	4%	28%	60%	33%
15 years or younger	7	1%	2,441	1%	349	40%	29%	57%	29%
Total	[illegible]		[illegible]			13%	25%	41%	48%

Data Sources: 2007/2008 EPA IPM, ARP, NBP Databases & Commercial Sources, MJB&A Analysis

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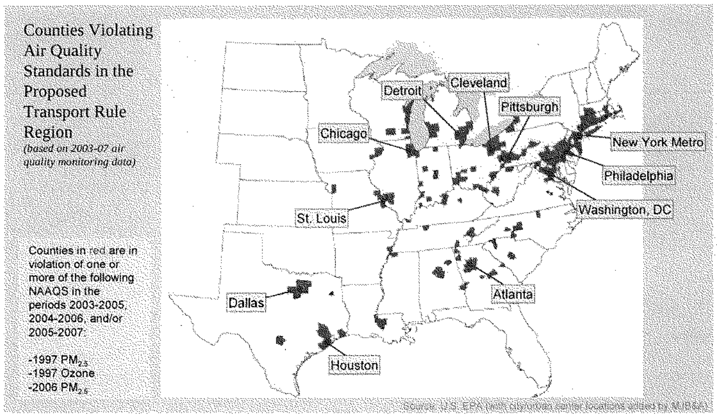
[53] *Id.*

Information included in the most recent annual *State of the Market Report* prepared by PJM's Independent Market Monitor ("IMM") suggests that fundamental economics, not the EPA regulations, are already challenging those units most likely to retire. In that report, the IMM identified over 11 GW of coal units at risk for retirement, since they "did not recover avoidable costs even with capacity revenues."[54] Of the 11 GW identified in the report, most operated less than 1,000 of the 8,760 hours in 2009 and tended to be significantly smaller with an average installed capacity of only 73 MW.[55] Of the 122 coal units in PJM with capacity less than or equal to 200 MW, 35 failed to recover their avoidable costs and another 52 were close to not recovering those costs. Therefore, in PJM, a region covering 13 states and DC, in addition to approximately 10 GW of coal generation that has or will be retired during the seven years from 2004 to 2011, another 11 GW faces a troubling economic outlook. As such, the units' economics already place them at risk of shutdown, regardless of EPA's future air regulations.

In reducing the air pollution emissions from some of the nation's most inefficient uncontrolled units, EPA will facilitate the development of cleaner, more efficient generation while improving air quality and reducing greenhouse gas emissions. The current levels of air pollution in certain regions of the country require industrial facilities and power plants to obtain emission offsets to expand their operations. This requirement discourages economic development due to the increased permitting and financial obligations compared to areas that meet federal and state air quality standards. Significantly as well, as shown in Figure 7, because these non-attainment areas are concentrated in highly populated areas, reducing emissions there will facilitate the development of cleaner, more efficient generation near electric load centers where it is needed most.

Additionally, the retirement of generating capacity that has been previously supported by transmission investment could create room on the transmission grid to handle power flows both within and outside the regions, or the addition of new generating capacity, without requiring attendant transmission upgrades. These considerations, too, will help mitigate reliability concerns and reduce the cost of upgrading the nation's power system infrastructure.

Figure 7 – Worst Air Pollution Near Population Centers


Counties Violating Air Quality Standards in the Proposed Transport Rule Region
(based on 2003-07 air quality monitoring data)
Counties in red are in violation of one or more of the following NAAQS in the periods 2003-2005, 2004-2006, and/or 2005-2007:
-1997 $PM_{2.5}$
-1997 Ozone
-2006 $PM_{2.5}$
Detroit
Cleveland
Pittsburgh
Chicago
New York Metro
Philadelphia
Washington, DC
St. Louis
Atlanta
Dallas
Houston

Source: U.S. EPA (with city/urban center locations added by MJB&A)

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[54] PJM, *State of the Market Report*, Vol. 1, March 11, 2010, p. 21.

[55] *Id.* Vol. 2 at p. 176.

III. EPA, DOE, FERC, And State Utility Regulators Have The Tools To Moderate Impacts On The Electric Industry And Manage Electric System Reliability

A. Statutory, Regulatory and Market Safeguards Exist To Mitigate Risks of Retirement On Reliability

Assorted risk management procedures under the CAA, the Federal Power Act ("FPA") and other statutes provide EPA, DOE, FERC, and the President tools to moderate potential impacts on electric system reliability. The procedures serve as a bridge, if necessary, to a permanent solution, helping ensure reliability while minimizing exposure to harmful air pollutants. EPA also has the authority to develop cost-effective regulatory approaches, such as the emissions trading mechanism proposed in the Transport Rule, that will enable greater compliance flexibility and flexibility in managing potential reliability issues.

In addition to the EPA's and President's authority to extend deadlines for installation of pollution controls described in Section II B, where necessary to maintain electric system reliability, DOE has the power under Section 202(c) of the FPA to override CAA-derived control requirements in limited emergency circumstances. In such emergency situations, including extended periods of insufficient power supply as a result of shortage of electric facilities, DOE has the discretion to issue unit-specific orders designed to maximize CAA compliance and minimize health risks.

Two examples of DOE's exercise of this authority illustrate the point. In 2003, the Secretary of Energy ordered energizing a new underwater cable connecting New Haven, Connecticut to Long Island, which had previously been constructed but remained inoperable due to legal actions appealing permits. Citing August 2003's massive electric service outage, the Secretary invoked his authority to alleviate the reliability emergency.[56]

DOE's actions related to the Potomac River plant serving Washington, DC provide another example. In 2005, the plant's owner, Mirant, had decided to shut down all five generating units at its Potomac River plant located outside Washington, DC. The DC Public Service Commission requested that DOE issue an emergency order directing Mirant to continue to operate the units, as their shutdown would have "immediate" and "drastic" effects on DC's electric system reliability. In conjunction with the EPA, which required Mirant to enter into a consent decree, DOE issued an Order[57] requiring Mirant to operate the plants under specific and limited circumstances tailored to relieve the risk of a DC area blackout, while avoiding to the full extent possible exceedances of federal air quality standards.

The well-established consent decree template, as used to address the Potomac River situation, provides EPA yet another tool to synthesize reliability and environmental concerns. By restricting a unit to operate for reliability purposes only, pending completion of any required transmission upgrades or replacement generation, such consent decrees can maintain reliability while minimizing adverse environmental impacts to the fullest extent possible.

Many regional wholesale competitive markets also have well-established forward capacity markets such as PJM's Reliability Pricing Model and New England's Forward Capacity Market, which are approved by FERC and overseen by independent market monitors, to facilitate and provide advanced notice of the retirement of inefficient units while maintaining reliability. Reliability impact studies are conducted for units that have announced retirement or fail to clear the forward capacity auctions, and those identified as being needed for reliability may continue to operate past their planned retirement date pursuant to "reliability must run" ("RMR") agreements. To help ensure reliability while minimizing adverse environmental impacts, the RMR agreements can provide the units operate only to maintain reliability. For example, Exelon Generation recently coordinated with PJM and the Pennsylvania Department of Environmental Protection ("PA DEP") to negotiate a consent decree and operating procedures related to an RMR agreement for its two retiring coal units, which require the units operate for reliability purposes only.[58]

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[56] DOE, *Order No. 202-03-2*, August 28, 2003. "I hereby determine that an emergency continues to exist in the Northeast United States due to a shortage of electric energy, a shortage of facilities for [...] the transmission of electric energy and other causes. [...] On August 14, 2003, the Northeast and Upper Midwest areas in the United States, as well as portions of Canada, experienced the largest electric transmission grid failure and electric service outage ever to occur in North America. Tens of millions of people were affected by this outage, and it presented profound risks to the public health and safety throughout the affected areas. [...] Only hours after the outage occurred, and after considering the unanimous recommendation of the North American Electric Reliability Council, the New York Independent System Operator (NYISO), ISO New England, Inc. (ISO-NE), and electric utilities in both New York and Connecticut in support of the issuance of an emergency order, I issued an order directing the NYISO and ISO-NE to require the Cross-Sound Cable Company, LLC (CSC) to operate the Cross-Sound Cable and related facilities as necessary to alleviate the disruptions in electric transmission service. The Cable was energized a short time thereafter."

[57] DOE, *Order No. 202-05-03*, December 20, 2005.

In addition to these established ISO/RTO procedures, advance analysis in the long range reliability planning processes should lead to rational and timely investments in new transmission that will mitigate any service reliability issues associated with future generation retirements. The local transmission owners currently play an important supplemental role in accomplishing this objective. For example, Commonwealth Edison ("ComEd"), the local transmission owner in Chicago, proactively filed an application with the Illinois Commerce Commission[59] seeking permission to enhance its transmission system. In its application, ComEd noted the identified upgrades would be required to maintain system reliability in the event that two of Midwest Generation's at-risk coal units, Fisk and Crawford, were to retire.[60]

Procedures also exist to protect electric system reliability in regions where coal plants are not part of an organized wholesale competitive market, but are owned by vertically-integrated utilities in traditionally regulated monopoly regimes. Generators regulated by state regulatory commissions have a legal obligation to reliably serve their customers, and to conduct long range resource planning. Typically, generators will have many options to meet their statutory obligation to serve including, but not limited to: (1) investing in existing plants; (2) building new plants; (3) decreasing load through DR and EE programs; (4) building transmission; or (5) a prudent combination of all those tools. Too, state regulators may adopt ratemaking policies to encourage such actions, including ones that address utilities' financial disincentives where aggressive EE and DR programs would otherwise produce lower revenues.

As such, FERC and other relevant agencies have a number of tools available to moderate the impacts of air emission regulations, while maintaining reliability and minimizing adverse environmental impacts. Moreover, EPA is also developing new water regulations under Section 316(b) of the Clean Water Act ("CWA"), new waste regulations, and greenhouse gas regulations affecting the electric power sector. EPA should consider efficiently coordinating these rules as it moves forward with its rulemakings to avoid possible reliability concerns.

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[58] *Commonwealth of Pennsylvania Department of Environmental Protection v. Exelon Generation Company, LLC.*, No. 382 MD 2010 (Pa. Cmmw. April 16, 2010) included in *Operating Procedures for Cromby Generating Station Unit No. 2 and Eddystone Generating Station Unit No. 2 as Required for Reliability Purposes* at Appendix 1, http://pjm.com/planning/generation-retirements/~/media/planning/gen-retire/must-run-operating-procedures.ashx (accessed August 6, 2010).

[59] Commonwealth Edison Company, *Application for authorization under Section 4-101 of the Illinois Public Utilities Act ("Act"), 220 ILCS § 5/4-101, or alternatively, for a Certificate of Public Convenience and Necessity, pursuant to Section 8-406 of the Act, to install, operate and maintain two new 345,000 volt electric transmission lines in Cook County, Illinois*, No. 10-0385 (Ill. Cir. June 11, 2010).

[60] Direct Testimony of Thomas W. Leeming, p. 2, Lines 25-35.

IV. CONCLUSION

Current industry practice and a review of applicable system data indicate the industry is well-positioned to respond to EPA's mission to "help millions of Americans breathe easier and live healthier" without threatening electric reliability. Generation plant capacity and availability, consumption levels and patterns, and transmission capacity and use must all be considered when judging the reliability impacts of environmental regulatory action.

The existing substantial excess capacity, the industry's proven track record to timely construct new generation and to efficiently coordinate the scheduling of planned outages, together with capacity upgrades, transmission enhancements, "smart grid" investments, fuel conversions, DR, and EE, should mitigate reliability concerns.

The industry has already successfully employed these various strategies to reliably meet customers' energy needs while reducing environmental impacts, and it will continue to do so in response to EPA's new regulations. As a final backstop, existing statutory, market and regulatory safeguards will facilitate the retirement of inefficient units, and an orderly transition to cleaner, more efficient generation.

ATTACHMENT A

Sampling of Recent Announcements of Scrubber Installations

Plant	Unit	State	Size (MW)	Highlights
Brandon Shores	1	MD	643	This significant environmental upgrade supports Constellation Energy's environmental stewardship efforts by: Reducing Maryland's coal-fired power plants SO2 emissions by an estimated 90 percent; Reducing existing mercury emissions by 90 percent; and Significantly reducing acid gases. http://www.constellation.com/portal/site/constellation/menuitem.[illegible]
Brandon Shores	2	MD	643	
Kingston	1	TN	135	The two scrubbers added at Kingston will remove sulfur dioxide from all nine boilers at the fossil plant, which can generate 10 billion kilowatt-hours of electricity per year. "We now have state-of-the-art control equipment on all of our units at Kingston, allowing us to generate the electricity needed by our customers," Kingston Plant Manager Leslie Fain said. "This translates into cleaner air in the Great Smoky Mountains and across the region." http://www.tva.gov/news/releases/[illegible]kingston_scrubber.html
Kingston	2	TN	135	
Kingston	3	TN	135	
Kingston	4	TN	135	
Kingston	5	TN	177	
Kingston	6	TN	177	
Kingston	7	TN	177	
Kingston	8	TN	177	
Kingston	9	TN	178	
Miller	3	AL	702	During peak construction, Alabama Power's $1.7 billion scrubber initiative was responsible for creating more than 2,300 jobs. "This investment is not only good for the environment, it's also good for Alabama's economy," Charles McCrary, Alabama Power president and CEO, said. http://[illegible]
Miller	4	AL	720	
Gaston	5	AL	861	
Barry	5	AL	750	
Coffeen	1	IL	340	"Our investment in these technologies reflects our commitment to environmental stewardship and our support for the communities we serve," says Chuck Naslund, AEE chairman, president and chief executive officer. "Through these projects, we have not only offered sustained permanent employment to hundreds of Illinoisans, but we have also provided jobs to contract employees who call Illinois home. Clearly these projects have had a positive impact on the economies of central and southern Illinois – areas hard hit by tough economic conditions." http://www.bloomberg.com/apps/news?[illegible]
Coffeen	2	IL	560	
Cardinal	1	OH	600	According to Buckeye Power, one of the owners of the Cardinal Plant, "the addition of these scrubbers means the Cardinal plant is able to reduce emissions while using Ohio coal, retaining jobs and economic benefits for eastern Ohio and the region." The unit 3 scrubber is still under construction. http://www.buckeyepower.com/[illegible]
Cardinal	2	OH	600	
Cardinal	3	OH	630	
Monroe	4	MI	775	DTE Energy will also be installing two additional FGD systems at Monroe units 1 and 2. According to DTE, "the $980 million project will create 900 jobs and be one of the largest construction projects in Michigan over the next few years." http://www.prnewswire.com/news-releases/[illegible].html
Monroe	3	MI	795	
Cliffside	5	NC	550	According to Duke, the scrubber control equipment at Cliffside Unit 5 will be completed by the Fall of 2010. Duke already has emission control scrubbers on all its large Carolinas coal plants—Allen, Marshall and Belews Creek. According to Duke spokesman Andy Thompson, Duke has reduced its NOx emissions by 60% since 1997 and SO2 emissions have fallen 70% since 2007. http://[illegible]
Bowen	1	GA	713	Scheduled for completion in early 2010, according to Georgia Power. http://www.georgiapower.com/[illegible]
Crist	6	FL	302	According to Gulf Power, since 2002, the company has reduced regulated emissions by more than 70 percent despite increased electricity demand from 120,000 new customers. With the scrubber system fully operational, Gulf Power will have reduced overall regulated emissions by more than 85 percent since 1990. http://[illegible]gulf-power-begins-scrubber-startup
Crist	7	FL	477	
Clifty Creek	1	IN	217	"The addition of these FGD systems represents a major commitment to environmental quality in southwestern Ohio and southeastern Indiana," said David E. Hart, vice president and assistant to the president of OVEC-IKEC. "The projects will also produce an economic boost to the two regions." The scrubber installations at Clifty Creek and Kyger Creek are scheduled for completion in 2010. http://[illegible]
Clifty Creek	2	IN	217	
Clifty Creek	3	IN	217	
Clifty Creek	4	IN	217	
Clifty Creek	5	IN	217	
Clifty Creek	6	IN	217	
Kyger Creek	1	OH	217	
Kyger Creek	2	OH	217	
Kyger Creek	3	OH	217	
Kyger Creek	4	OH	217	
Kyger Creek	5	OH	217	

Plant	Unit	State	Size (MW)	Highlights
Chalk Point	1	MD	342	"We are making a major investment to ensure a reduction in emissions," said Edward R. Muller, Mirant chairman and CEO. "This equipment offers an excellent solution for substantially improving air quality while maintaining system reliability and efficient power generation for consumers and businesses." http://investor.mirant.com/releasedetail.cfm?releaseid=281567
Chalk Point	2	MD	341	
Morgantown	1	MD	624	
Morgantown	2	MD	620	
Dickerson	1	MD	182	
Dickerson	2	MD	182	
Dickerson	3	MD	182	
Brunner Island	1	PA	340	According to PPL's website, "[The plant's scrubber is now operating as designed, thanks to plant employees who safely made the final connections between the plant and the scrubber during a period maintenance outage." http://www.pplweb.com/ppl+generation/ppl+brunner+island.htm
Brunner Island	2	PA	387	
Brunner Island	3	PA	744	
Hatfield's Ferry	1	PA	530	According to an Allegheny Energy fact sheet, "[The 'scrubbers'] will remove approximately 95 percent of the sulfur dioxide (SO2) emissions and significantly reduce mercury emissions from the station… In addition to improving the environment, the scrubber system will enable Hatfield's Ferry to purchase more local coal, which will preserve regional coal mining and related coal mining support jobs. The project will bring approximately 800 construction jobs to the region for a period of about three years. Additional full-time positions will be added to operate and maintain the scrubbers." http://www.alleghenyenergy.com/Newsroom/Scrubber-Hat2page.pdf
Hatfield's Ferry	2	PA	530	
Hatfield's Ferry	3	PA	530	
Hudson	2	NJ	585	According to PSEG Power, advanced emissions controls would be installed at Hudson by 2010. Scrubbers at its Mercer plant are scheduled for completion in late 2010. http://www.investor.pseg.com/releasedetail.cfm?ReleaseID=322812
Mercer	1	NJ	315	
Mercer	2	NJ	316	

Source: MJB&A analysis.

ATTACHMENT B

Recent Coal Plant Retirement Announcements

Name	Owner	State	Installed Capacity (MW)	Age (years)	Advanced SO_2/NO_x Controls
Weatherspoon	Progress Energy	NC	48	60	None
Weatherspoon	Progress Energy	NC	49	59	None
Weatherspoon	Progress Energy	NC	76	57	None
L V Sutton	Progress Energy	NC	83	55	None
L V Sutton	Progress Energy	NC	102	54	None
L V Sutton	Progress Energy	NC	403	37	None
H F Lee	Progress Energy	NC	79	57	None
H F Lee	Progress Energy	NC	77	58	None
H F Lee	Progress Energy	NC	248	47	None
Cape Fear	Progress Energy	NC	173	51	SNCR
Cape Fear	Progress Energy	NC	144	53	SNCR
Cameo	Xcel Energy	CO	54	49	None
Arapahoe	Xcel Energy	CO	47	58	None
Arapahoe	Xcel Energy	CO	112	55	None
Wabash River	Duke Energy	IN	85	53	None
Wabash River	Duke Energy	IN	85	55	None
Wabash River	Duke Energy	IN	85	56	None
Wabash River	Duke Energy	IN	85	54	None
Wabash River	Duke Energy	IN	318	41	None
John Sevier	TVA	TN	176	53	SNCR
John Sevier	TVA	TN	176	52	SNCR
John Sevier	TVA	TN	176	54	SNCR
John Sevier	TVA	TN	176	54	SNCR
Cromby	Exelon	PA	144	55	SNCR + Scrubber
Eddystone	Exelon	PA	293	49	SNCR + Scrubber
Eddystone	Exelon	PA	279	50	SNCR + Scrubber
Richard Gorsuch	American Municipal Power	OH	50	58	None
Richard Gorsuch	American Municipal Power	OH	50	58	None
Richard Gorsuch	American Municipal Power	OH	50	58	None
Richard Gorsuch	American Municipal Power	OH	50	58	None
Indian River	NRG Energy	DE	82	51	None
Indian River	NRG Energy	DE	177	44	None
Jack McDonough	Southern Co	GA	258	46	None
Jack McDonough	Southern Co	GA	250	45	None
Hunlock	UGI	PA	50	51	None
Will County	Midwest Generation	IL	188	55	None
Will County	Midwest Generation	IL	184	55	None
Boardman	Portland General Electric, Others	OR	585	29	None
Howard Down	Vineland Municipal Electric Utility	NJ	25	41	None
TOTAL			[illegible]		

Source: MJB&A analysis based on U.S. EPA Acid Rain Program database and U.S. EIA File 860.

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Analysis Group
ECONOMIC, FINANCIAL and STRATEGY CONSULTANTS

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A Reliability Assessment of EPA's Proposed Transport Rule and Forthcoming Utility MACT

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A Reliability Assessment of EPA's Proposed Transport Rule and Forthcoming Utility MACT

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A Reliability Assessment of EPA's Proposed Transport Rule and Forthcoming Utility MACT

Executive Summary

In this report, we:[1] (1) predict incremental coal plant retirements and pollution control retrofits resulting from US Environmental Protection Agency (EPA) proposed and forthcoming air regulations;[2] and (2) assess their impact on electric system reliability. The specific air regulations we considered in our analysis are the EPA's proposed Clean Air Transport Rule regulating SO_2/NO_x interstate pollution transport (Transport Rule) and forthcoming hazardous air pollutants regulations (utility MACT) described more fully in the Introduction section of this paper. Implementing these regulations will require some coal generators to install pollution control equipment in order to continue operations. However, given the recent discoveries of abundant, domestic natural gas supplies, a competing fuel for electric generation, as well as reduced electricity demand, coal plant owners may elect to retire some existing plants rather than investing the capital necessary to install pollution controls. Nonetheless, we conclude that electric system reliability can be maintained while the industry complies with EPA's air regulations.

The number of projected coal plant retirements nationwide is relatively small compared to historical US net additions of generation capacity, and the electric sector has demonstrated repeatedly the ability to expand the generation fleet at a rate well in excess of projected capacity needs. Although we predict that a handful of areas will have de minimis or modest shortfalls due to predicted retirements, adequate reserve margins can be maintained by better utilizing existing supply capacity, installing new generation, and increasing load management. Additionally, existing federal statutory, state regulatory, and regional transmission organization (RTO) market safeguards can be utilized to maintain a reliable electric system.

Some observers have expressed concern that accelerated coal unit retirements might adversely impact electric system reliability. To evaluate that concern, we:

1. Forecasted coal retirements in the US under an aggressive policy representation consistent with the Transport Rule and utility MACT (utility MACT/CAIR NO_x).[3]

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[1] This report was prepared by Charles River Associates (CRA) for Exelon Corporation.

[2] Notably, approximately 6 GW of retirements are already planned, driven by low power prices which are due to low natural gas prices and low electricity demand.

[3] EPA has indicated that the Transport Rule's NO_x cap will be tightened in the near future ("Transport Rule II"), so we modeled the Clean Air Interstate Rule (CAIR) NO_x policy instead of the current Transport Rule's NO_x policy because it is more stringent and likely a better representation of Transport Rule II.

2. Provided a reliability analysis for the Eastern Interconnection[4] based on expected load growth, likely new generation additions, and projected coal retirements at the RTO level,[5] North American Electric Reliability Corporation (NERC) regional level, and NERC subregional level.

3. Identified actions that can be taken to maintain system reliability.

Our conclusion that EPA air regulations can be implemented without adversely impacting electric system reliability comports with other industry reports that have been released in the past several months.[6] Most recently, NERC published its assessment of possible impacts of four EPA regulations, including the air regulations examined in this paper. NERC concluded that of the four regulations assessed, EPA's potential 316(b) water regulations would have the greatest impact on reliability, and further urged coordinating implementation of EPA's various regulations to mitigate reliability impacts.

When considering EPA's air regulations alone, NERC actually predicts fewer retirements than we do, even under its "strict case" scenario. Additionally, NERC, as well as the M.J. Bradley & Associates/Analysis Group report, identify a suite of industry tools, some of which are discussed in this paper, that can be utilized to mitigate any reliability impact of the EPA air regulations.[7]

Specifically, our analysis reaches the following conclusions:

- **Coal plant retirements will not adversely impact reliability.** The existing US coal fleet has about 314 GW of capacity, about 265 GW of which is located in the Eastern Interconnection. When considering both the currently planned 6 GW of retirements, plus those driven by an aggressive utility MACT/CAIR NO_x policy, we project a total of 35 GW of coal retirements in the Eastern Interconnection and 39 GW nationwide by 2015. To put that in perspective, the 35 GW represents less than 5% of the Eastern Interconnection's more than 730 GW of total capacity.

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[4] See definition of Eastern Interconnection in footnote 21. The US portion of the Eastern Interconnection contains about 73% of the electric generation capacity in the US.

[5] The RTOs in the Eastern Interconnection are: Independent System Operator (ISO) New England, the New York ISO, the PJM Interconnection, the Midwest ISO, and the Southwest Power Pool.

[6] M. J. Bradley & Associates/Analysis Group, "Ensuring a Clean, Modern Electric Generation Fleet while Maintaining Electric System Reliability," August 2010 (http://www.mjbradley.com/documents/MJBAandAnalysisGroupReliabilityReportAugust2010.pdf); North American Electric Reliability Corporation, "2010 Special Reliability Scenario Assessment: Resource Adequacy Impacts of Potential US Environmental Regulations," August 2010 (http://www.nerc.com/files/EPA_Scenario_Final_20101026.pdf); and ICF International, "EEI Preliminary Reference Case and Scenario Results," May 21, 2010.

[7] NERC 2010 Special Reliability Scenario Assessment Report, p. 40 and M. J. Bradley/Analysis Group Report, pp. 22-23.

- ➢ These projected retirements are relatively small in comparison to historical US net additions of generation capacity. For example, during the five-year period between 1999 and 2004, the net increase in US generating capacity was 177 GW, more than four times what is projected to retire in the US by 2015.
- ➢ Notably, the average age of the projected retiring units in the Eastern Interconnection is 55 years.[8] Many of these older units are already nearing the end of their design life expectancy.

- **After projected coal retirements, all five eastern RTOs have sufficient capacity to maintain reliability without any new resources beyond those that are already under construction.** Even excluding planned new generation in the permitting and site preparation stage, and after accounting for coal retirements resulting from the aggressive utility MACT/CAIR NO_x policy, all of the eastern RTOs have more than sufficient total resources to meet overall RTO reserve margin requirements in 2015. Although we project a few localized resource needs within the RTOs, these can be addressed through existing capacity markets and other tools discussed in this paper.

- **Modest capacity needs projected in the NERC regions and subregions can be easily met**. At the NERC regional level our analysis shows the utility MACT/CAIR NO_x policy drives only de minimis capacity shortfalls in two regions and a modest shortfall in another. At the NERC subregional level, one larger – but still manageable – shortfall is expected.[9] Two other subregional shortfalls are de minimis and modest. We believe that all of these shortfalls can be met with existing industry tools, such as:
  - ➢ **New Gas Generation Construction** – Our economic modeling shows that when new capacity is required, gas-fired generation is often the most economic alternative. In fact, the existence of abundant, inexpensive domestic natural gas resources not only is a driver of retirements but also will facilitate the transition to a cleaner generation fleet. History has shown that new gas units can be planned, permitted, and constructed in short periods of time. For example, in the Virginia-Carolina NERC subregion (VACAR), which our analysis indicates has the greatest need, almost 12 GW of gas-fired capacity

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[8] CRA calculated the capacity-weighted average age of the coal units that retire by 2015 in the Eastern Interconnection in its simulation of the utility MACT/CAIR NO_x policy. The result of the calculation was 55 years.

[9] This larger projected subregional shortfall would mostly exist in the absence of the forthcoming air pollution regulations assessed in this paper.

came online between 2000 and 2004, which is significantly more than its projected capacity shortfall of 6.3 GW.

- **Load Management** – Load management tools, such as demand response and energy efficiency programs, are growing rapidly and have the capability to offset some of the projected coal retirements. Some of the NERC subregions with larger capacity shortfalls also have the greatest untapped potential for substantially increasing load management resources. For example, in the VACAR region, load management accounts for 3.4% of resources at peak, while in the New England region, load management accounts for close to 10% of peak resources.

- **Coal to Gas Conversion** - Depending on the local availability of natural gas, existing coal units can be converted to natural gas for a relatively modest cost.[10] For example, in the Southeast Reliability Corporation (SERC) region, which has a de minimis projected capacity shortfall of 0.6 GW, about 11 GW of coal plants already have natural gas pipeline service and have natural gas as a secondary fuel option.

- **Alternative Technologies and Tools** - Application of alternative and lower cost pollution control technologies and other regulatory tools could realistically result in even less coal plant retirements than we predict by 2015.[11]

- **Additional regulatory safeguards exist to protect reliability.** To address any remaining reliability concerns, the EPA Administrator, the Secretary of Energy, and the President each have authority under the Clean Air Act to extend compliance by one to two years under specific circumstances. For example, in August 2005, to protect reliability, the Secretary of Energy used his authority to prohibit Mirant from retiring its Potomac River plant. Mirant subsequently retrofitted the Potomac River plant, which is still in service today.[12] Additionally, RTOs have market rules and

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[10] In its December 20, 2000 regulatory finding, EPA decided that natural gas-fired electric steam generation units are not subject to HAPs regulation (65 FR 79826). This finding did not apply to combustion turbines.

[11] The Institute of Clean Air Companies (ICAC) stated in recently filed comments, "ICAC would like to emphasize that the competition in the [air pollution control] industry in the last decade has matured and diversified the industry and has led to the development of many emission reduction technologies that are not as capital-intensive as the 'big-ticket' items of SCR, FGD, and baghouses. However, these less capital-intensive technologies can obtain significant reductions that, depending on the regulatory requirements, may allow a much more economical approach in the short-term." ICAC comments in *National Emission Standards for Hazardous Air Pollutants for Major Sources: Industrial, Commercial, and Institutional Boilers (ICI) and Process Heaters;* 75 FR 32006-32073 (June 4, 2010), filed on August 23, 2010, p. 2.

[12] In 2005, Mirant Corporation ceased operations at its Potomac River Generating Station in Alexandria, Virginia, after learning the plant's operations were causing exceedances of the National Ambient Air Quality Standards (NAAQS). In response, the Secretary of Energy responded to a petition and issued an

> procedures under the Federal Energy Regulatory Commission's (FERC) jurisdiction that will serve to mitigate reliability impacts, as do state regulatory commissions in traditional cost-of-service states. Current EPA, Department of Energy (DOE), and FERC coordination should also considerably mitigate any reliability concerns.[13]

In summary, modeling an aggressive policy implementation of EPA's proposed and forthcoming air regulations, we demonstrate, consistent with other industry reports, that with prompt action and industry coordination, electric system reliability can be maintained. Of the areas we analyzed - 5 RTOs, 6 NERC Regions, and 7 NERC subregions - we project that after predicted coal retirements, most still have capacity surpluses. At the NERC regional level, we predict that two regions will have de minimis shortfalls (relative to resource adequacy requirements) and another region will have a modest shortfall. At the NERC subregional level, there are three subregions that emerge as having shortfalls – one is de minimis, one is modest, and the other is larger, but still manageable. Notably, the larger shortfall would exist even in the absence of the forthcoming EPA regulations and planning processes, new gas-fired plants, and incremental load management can easily address this shortfall.

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emergency order under Federal Power Act section 202(c) directing Mirant to operate the coal-fired plant only under certain, limited circumstances tailored to relieve the reliability risk while also mitigating the air quality issues.

[13] An interagency task force among FERC, EPA, and the White House Council on Environmental Quality already exists and has been meeting for months to consider and model solutions to address the impact of the various EPA regulations. In an October 26 *Electric Light & Power* article, FERC Chairman Jon Wellinghoff responded to the NERC 2010 Special Reliability Scenario Assessment Report by saying, "We are aware of the potential problems, and we are working in an interagency way to solve them....it doesn't raise any concerns that I wasn't already aware were there." http://www.elp.com/index/from-the-wires/wire_news_display/1290063498.html

Introduction

Proposed and Forthcoming Air Regulations

In the two decades following the Clean Air Act Amendments of 1990 (CAA), the majority of coal plants have installed pollution controls to reduce air emissions. Over the next several years, the EPA will implement regulations that will further reduce harmful air emissions. Specifically, on July 6, 2010, the EPA proposed the Clean Air Transport Rule to reduce SO_2 and NO_x "emissions within 32 states in the eastern United States that affect the ability of downwind states to attain and maintain compliance with the 1997 and 2006 fine particulate matter (PM2.5) national ambient air quality standards (NAAQS) and the 1997 ozone NAAQS."[14] The Transport Rule is intended to replace CAIR, which was remanded to EPA by the DC Circuit Court of Appeals in December 2008. At the time of writing this paper, however, CAIR is still the rule in effect since the final Transport Rule is not anticipated until the spring of 2011.

In addition, pursuant to consent orders, by the end of 2011, EPA is required by the court to issue final "utility MACT" rules regulating hazardous air pollutants (HAPs) emitted by electric generators, using maximum achievable control technology (MACT) standards as set forth in Section 112(d) of the CAA.[15] Utility MACT will likely regulate mercury, non-mercury metals (e.g., arsenic, lead, nickel, chromium), and acid gases (e.g., hydrochloric acid, hydrofluoric acid, cyanide), all of which the CAA designates as HAPs. Utility MACT will impact coal-generating units in particular,[16] causing some units to install pollution control equipment and others to retire.

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[14] 75 FR 45210 (August 2, 2010); 31 states and the District of Columbia are covered by the Transport Rule.

[15] EPA attempted to regulate HAPs from coal plants and other sources through the Clean Air Mercury Rule (CAMR), but in 2008, the court vacated the rule as invalid. Among other things, the court found that EPA was required to regulate HAP emissions from power plants using MACT standards pursuant to Section 112 of the CAA. Shortly after, the American Nurses Association and other organizations sued EPA, resulting in a consent decree requiring EPA to issue draft MACT standards by March 16, 2011, and final MACT standards by November 16, 2011.

[16] EPA is under no compulsion to establish MACT standards for gas-fired steam electric generation units. During the Clinton administration, EPA determined under section 112(n)(1)(A) that gas-fired steam electric generation units did not warrant regulation under section 112 and therefore decided not to list them as targets for the MACT standard-setting process. That decision has never been challenged in the DC Circuit. EPA's determination did not apply to combustion turbines.

Assumptions Used for Analysis

As stated above, the purpose of this analysis is to assess the retirement and reliability implications of the proposed Transport Rule and forthcoming utility MACT regulations.[17] As the utility MACT rule has not yet been proposed, we made certain assumptions for our analysis. The key unknown element of utility MACT is which technologies will be required for compliance. Many observers believe that utility MACT will require wet scrubbers, sorbent injection (e.g., activated carbon), and advanced particulate control (e.g., fabric filters) for HAPs control. Others, however, believe that MACT compliance may allow lower cost and relatively inexpensive dry scrubbing options using sorbents to capture acid gases and metals (e.g., trona with activated carbon injection).[18] For purposes of our modeling, we assumed the more expensive technologies will be required, that is, activated carbon sorbent injection (ACI), fabric filter, and wet flue gas desulfurization (FGD) scrubbers.[19]

With respect to the Transport Rule, it has a relatively strict SO_2 cap, particularly when it tightens in 2014. However, as our aggressive utility MACT representation forces scrubbers to be installed on every operating coal unit, we do not model the Transport Rule SO_2 cap because it will be met *a priori* when a unit complies with our assumed utility MACT policy. On the other hand, the NO_x requirements under CAIR are more stringent in aggregate than the state-specific requirements under the proposed Transport Rule. EPA indicated in its Transport Rule Notice of Proposed Rulemaking that further complementary action on NO_x was forthcoming, perhaps in concert with a more strict ozone NAAQS. Thus, to represent future NO_x policy, we model the more aggressive CAIR NO_x requirements. Although we do not impose or model the CAIR requirements on a state-level because CAIR does not restrict interstate trading as the Transport Rule does, the CAIR NO_x policy is more stringent in aggregate than proposed in the Transport Rule.

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[17] There are other potential regulations that could impact coal unit retirement decisions. Such regulations address cooling water, 316(b), and ash containment/disposal. In this paper, we do not address or discuss the electric sector impacts of future water and ash regulations.

[18] See, e.g., the ICAC letter to Senator Thomas Carper, November 3, 2010; http://www.icac.com/files/public/ICAC_Carper_Response_110310.pdf; pp. 1, 3, in which they stated "Less resource- and time-intensive technologies are available to be quickly deployed, offering the electric generating industry the needed flexibility to comply with the proposed Clean Air Transport Rule and the upcoming utility MACT. For example, direct sorbent injection (DSI) and dry scrubbing technology installation times are approximately 12 and 24 months, respectively" and "Going forward, ICAC expects a wide range of technologies will be available to provide flexibility for utility compliance strategies. In particular, we expect greater use of both DSI and dry scrubbing technologies, such as circulating dry scrubbers (CDS) and spray dryer absorber (SDA) technology, due to future backend water and disposal requirements. The added advantages of using these technologies are fewer resources required and shorter installation times – 12 months for DSI and 24 months for a dry scrubber. Moreover, the next round of [electric generation unit] control installations will likely be on smaller coal-fired units, and DSI and dry scrubbing are well-suited to smaller footprints and high-sulfur bituminous coal applications."

[19] Selective catalytic reduction units (SCRs) are another technology that oxidizes elemental mercury into a form that can be more easily captured in a scrubber. There is the potential that SCR requirements could also be part of the utility MACT. We have not included SCRs in our utility MACT representation and have therefore not chosen the most expensive representation possible. However, our utility MACT representation is likely towards the more expensive end of the spectrum of what utility MACT might entail, particularly if wet scrubbing is not determined to be MACT.

As for timing, the applicable consent decree requires a final utility MACT rule by November 2011 and pollution control equipment is required to be installed within three years of utility MACT promulgation.[20] This also coincides with CAIR's tightened NO_x requirement; therefore, when evaluating retirements and reliability impacts, we used 2015 as the implementation date.

In summary, our representation of future SO_2, NO_x, and HAPs policy is aggressive and assumes the CAIR NO_x policy plus a package of ACI, fabric filter, and FGD scrubber technology requirements to represent utility MACT. Together, we call this the utility MACT/CAIR NO_x policy. The technology requirements must be met by 2015 while CAIR stays on its current schedule (which tightens in 2015). If we had performed the modeling with 2016 as the first year of implementation, the level of retirements would have been virtually the same as we found for 2015.

Methodology

We used CRA's North American Electricity and Environment Model (NEEM) to estimate coal unit retirements under the utility MACT/CAIR NO_x policy representation described above. NEEM optimizes generation operation in each major region in the US, taking into account power transfer limits among regions. NEEM optimizes retirements, unit environmental retrofits, and new capacity additions by region over a 60-year period, taking into account the operating and cost characteristics of existing capacity and the capital and operating costs of potential new capacity. Appendix B details NEEM's input assumptions on load growth, fuel costs, and pollution control equipment. We used NEEM's forecasted coal retirements as the key inputs to our 2015 reliability analysis.

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[20] CAA Section 112(i).

Reliability Implications of Projected Retirements

NERC is the electric reliability organization certified by FERC to establish and enforce reliability standards for the North American bulk-power system. The eight NERC reliability regions are shown in Figure 1.

Some NERC regions are divided further into subregions as shown in Figure 2. In the eastern US, the SERC region is subdivided into five subregions (Central, Delta, Gateway, Southeastern, and VACAR), while the NPCC region is divided into two subregions (New York and New England). As can be seen from Figure 3, which shows the RTOs in the Eastern Interconnection,[21] the New York and New England subregions in NPCC correspond to the New York ISO and the New England ISO, respectively, and the Southwest Power Pool (SPP) NERC region corresponds to the SPP RTO.

Aggregate Projected Coal Retirements

The US currently has about 314 GW of coal-fired capacity installed, with about 10 GW more scheduled to come online over the next two years. Of the 314 GW of existing coal-fired capacity, 169 GW already have FGD scrubbers and 52 GW are scheduled to add FGD scrubbers over the next four years, leaving about 92 GW, or only 30% of existing coal capacity that will need to either install pollution control equipment or retire.[22]

Our analysis projects approximately 35 GW of coal retirements in the Eastern Interconnection between 2010 and 2015, which includes about 6 GW of already announced retirements. Accordingly, we project approximately 29 GW of incremental retirements as a result of the aggressive utility MACT/CAIR NO_x policy we modeled. Table 1 shows these projected retirements, the bulk of which are in the ReliabilityFirst (RFC) and SERC regions.[23]

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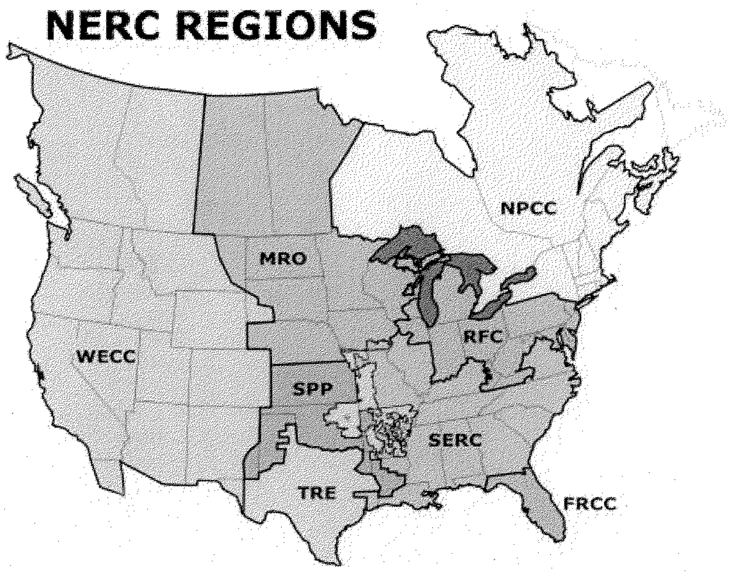
[21] The Eastern Interconnection consists of a large portion of the US and Canadian transmission system east of the Continental Divide, with the exception of a large portion of Texas, which is a separate interconnected system. Today, the Eastern Interconnection consists of six NERC reliability regions and five RTOs. All of the Eastern Interconnection transmission and generation is in one of the NERC regional reliability organizations, but only a portion of the generation and transmission is in an RTO. Although the NERC regions have responsibility for monitoring and enforcing NERC reliability standards in practice, within the RTO footprints the RTOs are ultimately responsible for taking the actions needed to ensure reliability in their control areas.

[22] New coal plants will have FGDs, SCRs, and fabric filters. Any additional controls that may be required to control HAPs at new coal plants (e.g., sorbent injection) will require little additional cost.

[23] We project only 4 GW of additional coal retirements outside of the Eastern Interconnection under the utility MACT/CAIR NO_x policy, bringing the total US projected coal retirements to 39 GW, when considering already planned retirements as well as those driven by the utility MACT/CAIR NO_x policy.

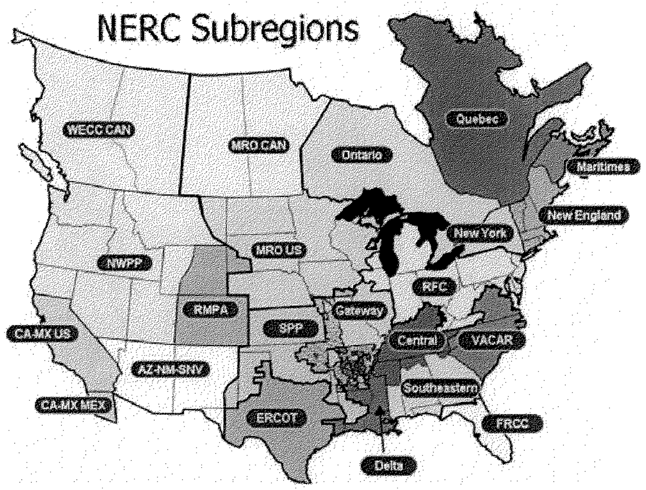
Notably, many of the already announced retirements, and projected retirements under our analysis, are driven by low natural gas prices caused primarily by the existence of abundant, inexpensive domestic natural gas resources. In other words, if we had used the higher natural gas prices that had existed only a few years ago in our modeling of the utility MACT/CAIR NO_x policy, the predicted retirement results would have been very different. Although low-priced natural gas presents economic challenges for existing plants, it will facilitate America's transition to a modern, cleaner generation fleet.

Figure 1. NERC Regions



Source: North American Electric Reliability Corporation (NERC)

Figure 2. NERC Subregions



Source: North American Electricity Reliability Corporation (NERC)

Figure 3. The Eastern Interconnection and RTOs

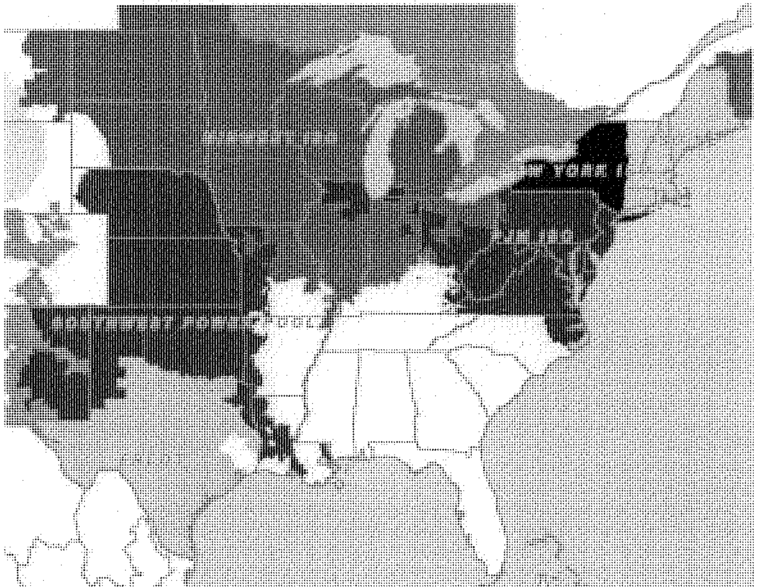


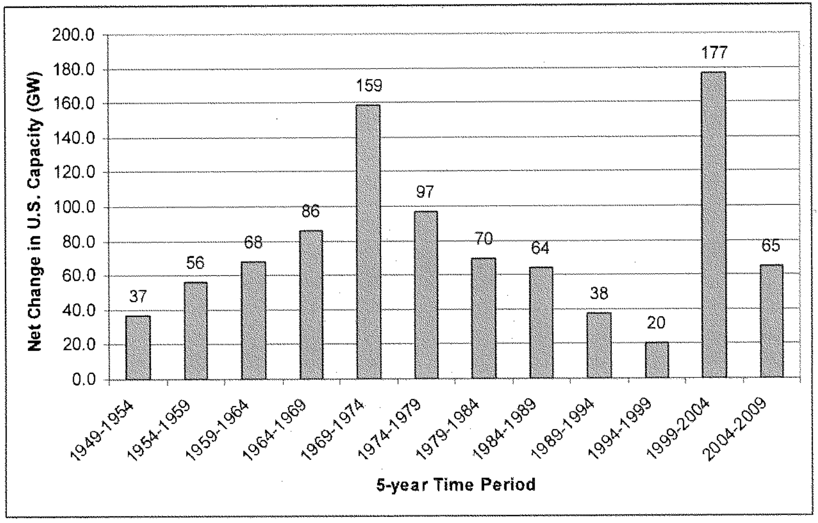
Table 1. Projected Coal Unit Retirements in the Eastern Interconnection under Utility MACT/CAIR NO_x

	Planned Retirements			Economic Retirements			Total Retirements		
NERC Region/Sub-Region	**No. Units**	**Retired Coal Capacity (MW)**	**Average Size (MW)**	**No. Units**	**Retired Coal Capacity (MW)**	**Average Size (MW)**	**No. Units**	**Retired Coal Capacity (MW)**	**Average Size (MW)**
Florida Reliability Coordinating Council	-	-	-	4	1,335	334	4	1,335	334
Midwest Reliability Organization	1	29	29	81	3,640	45	82	3,668	45
Northeast Power Coordinating Council	1	109	109	12	718	60	13	827	64
New England	1	109	109	5	370	74	6	479	80
New York	-	-	-	7	348	50	7	348	50
ReliabilityFirst	18	2,355	131	130	10,306	79	148	12,660	86
SERC Reliability Corp	28	3,232	115	122	12,716	104	150	15,948	106
Central	-	-	-	39	4,329	111	39	4,329	111
Delta	-	-	-	7	343	49	7	343	49
Gateway	-	-	-	10	641	64	10	641	64
Southeastern	5	750	150	30	4,407	147	35	5,157	147
VACAR	23	2,482	108	36	2,997	83	59	5,479	93
Southwest Power Pool Inc	-	-	-	17	664	39	17	664	39
Total	**48**	**5,724**	**119**	**366**	**29,378**	**80**	**414**	**35,102**	**85**

Note: Economic retirements are those that are not already planned, but are driven by environmental policy and increasing operating and maintenance costs.

To put the magnitude of the forecasted retirements in perspective, we reviewed the Energy Information Administration Annual Energy Review 2009 data, shown in Figure 4 for the entire US, indicating the historical net changes in electric generation capacity in the US over all of the five-year periods between 1949 and 2009. As the data reveal, the electric sector has repeatedly demonstrated the ability to expand the generation fleet at a rate well in excess of capacity needed to replace our projected retirements. For example, in the 1999-2004 period, the net increase in US generating capacity was 177 GW, more than four times the amount of US capacity we project to retire by 2015 due to the utility MACT/CAIR NO_x policy. As shown below, since 1949, in nine out of twelve periods the electric sector has added more capacity than is needed to replace the net projected US retirements arising from the utility MACT/CAIR NOx policy we modeled.

Figure 4. Net Changes in US Generating Capacity (GW)



Accordingly, based on the historical information in Figure 4, it is completely reasonable to expect that the 39 GW of projected coal retirements, and any incremental capacity needed due to demand growth, could be met easily with new capacity construction alone. In addition to new capacity, however, the industry possesses several other tools to manage reliability, such as increased load management programs and coal-to-gas conversion, discussed later in this paper.

Reliability Analysis at RTO Level

Our reliability analysis shows that all of the RTOs have sufficient resources to meet reserve margin requirements by 2015, even after accounting for coal retirements that result from the utility MACT/CAIR NO_x policy. This is true even if planned new additions in the permitting and site preparation stages are excluded from the calculations.

Table 2 shows the balance of loads and capacity resources for each RTO.[24] A more detailed table is provided in Appendix D. Our modeling first determined that all RTOs in the Eastern Interconnection have sufficient resources to meet reserve margin requirements by 2015 before accounting for the utility MACT/CAIR NO_x policy (see Column A). We then reduced the reserve margins to reflect the estimated coal plant retirements from the utility MACT/CAIR NO_x policy and found that reserve margin requirements would still be exceeded in all RTOs (see Column B). Finally, we added in all new additions in the permitting stage expected to be in service by 2015, which again shows that reserve margin requirements will be exceeded in all RTOs in the Eastern Interconnection (see Column C).

Table 2. Loads and Resources by 2015, RTO Level

RTO	*2015 Net Internal Demand Estimate (MW)	Required Reserve Margin (%)	Required Capacity (MW)	Projected Capacity PLUS Net Firm Transactions (MW), 2015	(A) 2015 Resource Adequacy Surplus / (shortfall) (MW)	Projected Coal Retirements by 2015, due to MACT / CAIR NOx (MW)	(B) Retirement-Adjusted 2015 Resource Adequacy Surplus / (shortfall) (MW)	+ New Additions by 2015 in Permitted Stage (derated MW), Energy Velocity	(C) Retirement-Adjusted 2015 Resource Adequacy Surplus / (shortfall), Reflecting Permitted Builds (MW)	Predicted Percentage Points Above (or Below) Required Reserve Margin in 2015 (%)
PJM	146,441	15.3%	168,846	178,061	9,215	7,529	1,686	2,350	4,036	2.8%
MISO	91,001	15.4%	105,015	127,088	22,073	7,074	14,999	435	15,434	17.0%
New England	26,180	15.0%	30,107	32,630	2,523	370	2,153	1,094	3,247	12.4%
New York	31,803	15.0%	36,573	38,892	2,318	348	1,970	192	2,162	6.8%
SPP	45,284	13.6%	51,442	53,409	1,966	664	1,302	102	1,404	3.1%

* "2010 NERC Summer Asssessment Total Internal Demand" PLUS "growth to 2015 implied by NERC 2009 ES&D" LESS "difference between Total Internal Demand and Net Internal Demand according to the 2010 NERC Summer Assessment" (for New England, New York, and SPP). For PJM, the PJM 2013/14 RPM Base Residual Auction Planning Parameters, total RTO load net of load management. For MISO, 2015 Coincident Net Internal Demand, Midwest ISO Transmission Expansion Plan (MTEP) 2009.

+ Planned new additions that are in the "permitted" or "site prep" status categories.

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[24] Column A shows the 2015 capacity resource surplus/(shortfall) before the coal retirements driven by the utility MACT/CAIR NO_x policy that we have estimated using NEEM. Column A reflects both planned additions (additions either under construction or in the testing phase as indicated by Energy Velocity) and planned retirements. Column B shows the surplus/(shortfall) after adjusting for our incremental coal retirement projections through 2015. Column C shows the surplus/(shortfall) after adding permitted additions (i.e., planned additions that have acquired permits or have both acquired permits and begun site preparation). Column C represents the resource adequacy surplus/(shortfall) that could be achieved under utility MACT/CAIR NO_x policy by doing nothing other than completing projects that are under construction and building those that already have been permitted. These calculations are explained further in the ***Estimating Reliability Impacts*** section in Appendix B.

Moreover, these RTOs have mechanisms in place to ensure that resource adequacy is maintained and new capacity is planned and built when needed. Each RTO has an installed reserve margin requirement and load serving entities (LSEs) are responsible for securing sufficient resources to meet those requirements. In the case of PJM and ISO New England, a centralized forward capacity market mechanism has been implemented, with the market operator acting as central buyer of capacity resources and allocating the costs back to LSEs.

In New York, the ISO has a short-term market for capacity designed to provide adequate compensation to new generation resources when needed. The monthly market is designed to support development of new capacity and provide incentives for LSEs to secure new capacity resources in order to avoid high short-term market prices.

The MISO market depends on self-supply and bilateral contracting by LSEs, supplemented by a voluntary short-term market, to meet the mandated requirements. LSEs that have not secured sufficient capacity are subject to substantial financial penalties. The MISO is also considering adopting a forward market mechanism for resource adequacy.

While SPP has no centralized capacity market, LSEs are subject to reserve margin requirements and must either develop new resources when needed or enter bilateral contracts with other suppliers.

Reliability Analysis at the NERC Regional Level

At the NERC regional level, our analysis reveals modest resource adequacy shortfalls that can be easily addressed by new capacity additions and other industry tools.

Table 3 shows the balance of loads and capacity resources for each NERC region.[25] A more detailed table is provided in Appendix D. Our modeling first determined that all NERC regions in the Eastern Interconnection have sufficient resources to meet reserve margin requirements by 2015 before accounting for the utility MACT/CAIR NO_x policy

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[25] Column A shows the 2015 capacity resource surplus/(shortfall) before the coal retirements driven by the utility MACT/CAIR NO_x policy that we have estimated using NEEM. Column A reflects both planned additions (additions either under construction or in the testing phase as indicated by Energy Velocity) and planned retirements. Column B shows the surplus/(shortfall) after adjusting for our incremental coal retirement projections through 2015. Column C shows the surplus/(shortfall) after adding in permitted additions (i.e., planned additions that have acquired permits or have both acquired permits and begun site preparation). Column C represents the resource adequacy surplus/(shortfall) that could be achieved under utility MACT/CAIR NO_x policy by doing nothing other than completing projects that are under construction and building those that already have been permitted. These calculations are explained further in the ***Estimating Reliability Impacts*** section in Appendix B.

(see Column A). When considering the utility MACT/CAIR NO_x policy, and including all planned new additions,[26] we found modest shortfalls in only three NERC regions (as shown in Column C): (1) 2,528 MW (6%) in MRO; (2) 583 MW (< 1%) in RFC; and (3) 638 MW (< 1%) in SERC.[27]

These modest shortfalls can be managed easily with construction of new gas-fired power plants and/or incremental load management. Not only can new gas units be planned, permitted, and constructed in less than three years,[28] filling most, if not all, of any capacity shortfalls, but regional shortfalls should also make construction of these units economically attractive. Any remaining shortfalls could be addressed by expanded load management programs.

Table 3. Loads and Resources by 2015, NERC Regional Level

NERC Region	*2015 Net Internal Demand Estimate (MW)	Required Reserve Margin (%)	Required Capacity (MW)	Projected Capacity PLUS Net Firm Transactions (MW), 2015	(A) 2015 Resource Adequacy Surplus / (shortfall) (MW)	Projected Coal Retirements by 2015, due to MACT / CAIR NOx (MW)	(B) Retirement-Adjusted 2015 Resource Adequacy Surplus / (shortfall) (MW)	+ New Additions by 2015 in Permitted Stage (derated MW), Energy Velocity	(C) Retirement-Adjusted 2015 Resource Adequacy Surplus / (shortfall), Reflecting Permitted Builds (MW)	Predicted Percentage Points Above (or Below) Required Reserve Margin in 2015 (%)
FRCC	47,330	15.0%	54,429	55,760	1,331	1,335	(4)	2,550	2,546	5.4%
MRO	42,681	15.0%	49,083	49,818	735	3,640	(2,905)	377	(2,528)	-5.9%
NPCC	60,894	15.0%	70,028	71,521	1,494	718	776	1,286	2,062	3.4%
RFC	186,008	15.0%	213,909	221,280	7,371	10,306	(2,935)	2,351	(583)	-0.3%
SERC	213,891	15.0%	245,975	252,120	6,145	12,716	(6,571)	5,934	(638)	-0.3%
SPP	45,284	13.6%	51,442	53,409	1,966	664	1,302	102	1,404	3.1%

* "2010 NERC Summer Asssessment Total Internal Demand" PLUS "growth to 2015 implied by NERC 2009 ES&D" LESS "difference between Total Internal Demand and Net Internal Demand according to the 2010 NERC Summer Assessment."

+ Planned new additions that are in the "permitted" or "site prep" status categories.

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[26] Permitted units are included in these estimates and can be completed quickly as they confront no regulatory hurdles.

[27] The FRCC, NPCC, and SPP regions do not have resource adequacy shortfalls, even after accounting for our projected retirements due to the utility MACT/CAIR NO_x policy.

[28] For example, in August 2009, the Tennessee Valley Authority (TVA) decided to construct an 880 MW combined-cycle facility adjacent to the John Sevier plant in Tennessee. The need for the new gas plant was determined after the US District Court in Western North Carolina set an aggressive timeline for installing new emission controls for the John Sevier coal plant or retiring that plant. TVA will have the new gas capacity online by January 1, 2012, less than two-and-a-half years from the date of the decision to build.

Reliability Analysis at the NERC Subregional Level

Based on our analysis, all but one of the NERC subregions in the Eastern Interconnection have sufficient resources to meet reserve margin requirements by 2015 before accounting for the utility MACT/CAIR NO_x policy. The exception is VACAR, which is projected to have a shortfall of 5,200 MW by 2015, prior to implementation of the utility MACT/CAIR NO_x policy.

Table 4 shows our loads and resources balance at the NERC subregional level.[29] A more detailed table is provided in Appendix D. After accounting both for already announced retirements plus incremental retirements driven by the utility MACT/CAIR NOx policy, six subregions have no resource adequacy shortfalls: FRCC, NPCC-New England, NPCC-New York, SERC-Delta, SERC-Gateway, and SPP (see Column C). We project the following three SERC subregions (in addition to MRO and RFC which were already identified and discussed in the NERC Regional Level section) to have resource adequacy shortfalls:[30] (1) 1,403 MW (3%) in Central; (2) 681 MW (1%) in Southeastern; and (3) 6,322 MW (9%) in VACAR. Significantly, only about 1,100 MW of VACAR's projected 6,322 MW shortfall results from the utility MACT/CAIR NO_x policy implementation.

Just as with the NERC regional analysis, the shortfalls in all the subregions can be addressed by construction of new gas-fired power plants and/or incremental load management, even in VACAR where the capacity needs are greatest. For example, in the VACAR region there is an opportunity for expanding load management to offset much of the projected economic retirements since load management resources only represent about 3.4% of peak load.[31] As other regions of the Eastern Interconnect demonstrate, load management resources can be used to meet much higher percentages of peak load. In the New York ISO, for example, about 7.5% of capacity resources are load management resources, and in the New England ISO they represent about 10% of capacity. In PJM, a total of 14,000 MW of load management, or about 9% of peak, has been offered into the

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[29] Column A shows the 2015 capacity resource surplus/(shortfall) before the coal retirements driven by the utility MACT/CAIR NO_x policy that we have estimated using NEEM. Column A reflects both planned additions (additions either under construction or in the testing phase as indicated by Energy Velocity) and planned retirements. Column B shows the surplus/(shortfall) after adjusting for our incremental coal retirement projections through 2015. Column C shows the surplus/(shortfall) after adding in permitted additions (i.e., planned additions that have acquired permits or have both acquired permits and begun site preparation). Column C represents the resource adequacy surplus/(shortfall) that could be achieved under utility MACT/CAIR NO_x policy by doing nothing other than completing projects that are under construction and building those that already have been permitted. These calculations are explained further in the ***Estimating Reliability Impacts*** section in Appendix B.

[30] The MRO and RFC subregions are identical to the MRO and RFC regions, and accordingly the shortfalls presented in Table 4 for those subregions are the same as those presented in Table 3. As already discussed, those shortfalls are modest and can be readily addressed by new capacity additions and other industry tools.

[31] NERC 2010 Summer Assessment Table 2b, p. 15.

Reliability Pricing Model (RPM) market, with almost half clearing, or about 6,800 MW clearing. Some of the increased load management resources in VACAR could come from the PJM RPM market in Dominion's region. Also notably, much of the uncleared load management resources are in locations that have a current surplus but are expected to have retirements, creating an opportunity for load management growth in those areas in the future.

New gas-fired capacity could also be added to manage any capacity shortfall. Our modeling shows that in many cases, building new gas-fired plants is an economic alternative to retrofitting older coal units with pollution control equipment. In fact, in the 2000 to 2004 period, almost 12,000 MW of gas-fired capacity came online in VACAR, about 6,000 MW greater than the projected shortfall.

Table 4. Loads and Resources by 2015, NERC Subregional Level

NERC Sub-Region	*2015 Net Internal Demand Estimate (MW)	Required Reserve Margin (%)	Required Capacity (MW)	Projected Capacity PLUS Net Firm Transactions (MW), 2015	(A) 2015 Resource Adequacy Surplus / (shortfall) (MW)	Projected Coal Retirements by 2015, due to MACT / CAIR NOx (MW)	(B) Retirement-Adjusted 2015 Resource Adequacy Surplus / (shortfall) (MW)	+ New Additions by 2015 in Permitted Stage (derated MW), Energy Velocity	(C) Retirement-Adjusted 2015 Resource Adequacy Surplus / (shortfall), Reflecting Permitted Builds (MW)	Predicted Percentage Points Above (or Below) Required Reserve Margin in 2015 (%)
FRCC	47,330	15.0%	54,429	55,760	1,331	1,335	(4)	2550	2,546	5.4%
MRO	42,681	15.0%	49,083	49,818	735	3,640	(2,905)	377	(2,528)	-5.9%
NPCC - New England	26,180	15.0%	30,107	32,630	2,523	370	2,153	1094	3,247	12.4%
NPCC - New York	31,803	15.0%	36,573	38,892	2,318	348	1,970	192	2,162	6.8%
RFC	186,008	15.0%	213,909	221,280	7,371	10,306	(2,935)	2351	(583)	-0.3%
SERC - Central	44,956	15.0%	51,699	53,262	1,563	4,329	(2,766)	1363	(1,403)	-3.1%
SERC - Delta	30,167	15.0%	34,692	40,111	5,419	343	5,077	513	5,590	18.5%
SERC - Gateway	19,883	11.9%	22,250	23,819	1,569	641	929	62	991	5.0%
SERC - Southeastern	52,889	15.0%	60,822	62,427	1,604	4,407	(2,802)	2121	(681)	-1.3%
SERC - VACAR	67,838	15.0%	78,014	72,814	(5,200)	2,997	(8,197)	1874	(6,322)	-9.3%
SPP	45,284	13.6%	51,442	53,409	1,966	664	1,302	102	1,404	3.1%

* "2010 NERC Summer Asssessment Total Internal Demand" PLUS "growth to 2015 implied by NERC 2009 ES&D" LESS "difference between Total Internal Demand and Net Internal Demand according to the 2010 NERC Summer Assessment."

+ Planned new additions that are in the "permitted" or "site prep" status categories.

Tools for Addressing Local and Regional Capacity Resource Needs

In addition to the industry tools discussed previously, such as construction of new generation and increased load management, several other tools and market and regulatory safeguards exist to alleviate any reliability issues caused by coal plant retirements. First, coal units can convert to natural gas to meet existing state pollution control requirements and anticipated utility MACT obligations. Second, in traditional cost-of-service markets, regulators can apply local regulatory protections to mitigate reliability concerns. Third, competitive electricity markets have proven, transparent rules and policies specifically designed to ensure sufficient resource adequacy and mitigate retirement impacts. Finally, existing broad statutory and regulatory safeguards can help preserve reliability in the unlikely event the tools discussed above prove inadequate.

Coal to Gas Conversion

EPA has determined that natural gas-fired electric steam generation units do not fall under HAPs regulations.[32] Thus, if a coal-fired unit were converted to natural gas, it would meet its obligations under the utility MACT. Many utilities are already doing exactly that to achieve their pollution control requirements. For example, Public Service Colorado (PSCo) planned to convert a coal unit, Arapahoe 4, to natural gas as part of a package of measures that also includes environmental retrofits, retirements, and unit replacement in response to Colorado's "Clean Air-Clean Jobs Act."[33] The Public Utilities Commission of the State of Colorado modified PSCo's plan to also convert Cherokee 4, a 352 MW coal unit to natural gas as well.[34]

Of the 264 GW of coal capacity in the Eastern Interconnection, about 41 GW have natural gas pipeline access and can use natural gas as a secondary fuel, and accordingly could pursue a similar strategy. In some circumstances, the cost of converting units can be economic[35] and the time to convert relatively short. In effect, a gas conversion replaces a coal unit with a natural gas peaking unit with about the same capacity as the original unit.

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[32] See December 20, 2000 regulatory finding (65 FR 79826). This finding does not apply to combustion turbines.

[33] See also, *Denver Post*, August 8, 2010, http://www.denverpost.com/frontpage/ci_15775014, "Xcel will start retrofitting its Denver-based Cherokee plant next year, converting 717 megawatts of generation to natural gas. The smaller Arapahoe plant would switch one unit to natural gas and another to a system designed to improve grid reliability, both by the end of 2013." "Xcel lays out natural-gas conversion plan for metro area."

[34] Final Order Addressing Emission Reduction Plan, Docket No. 10M-245E, Public Utilities Commission of the State of Colorado, December 15, 2010.

[35] "Complementary Technology and Conversion of Coal-Fired Plants to Natural Gas - Calpine will use natural gas as the primary fuel source for the Conectiv fleet, including two plants that were previously fueled by coal." Calpine Investor Relations Statement, July 1, 2010, http://phx.corporate-

Market Safeguards

All markets in the Eastern Interconnection have procedures in place to protect electric system reliability. These market safeguard procedures include analysis and planning to enable rational and timely action to avoid capacity shortfalls. For example, in some regional wholesale competitive markets operated by RTOs, forward capacity markets facilitate advanced notice of capacity needs and provide price signals to incent new entry. In wholesale markets with vertically-integrated, traditionally regulated utilities, there is a legal obligation to serve load and state regulatory commissions require long-range, integrated resource planning.

RTO Markets

PJM and New England ISO's market-based forward capacity programs play an essential role in maintaining reliability, ensuring that any capacity shortfall is identified and addressed well in advance of any reliability issue. At the core of PJM's RPM is a region-wide Base Residual Auction (BRA), conducted about 40 months prior to each Delivery Year.[36] All existing capacity resources are required to submit an offer into each BRA, and developers may submit offers of proposed resources.

RPM provides a mechanism for including either the replacement cost or the economic cost of retrofitting existing coal facilities to comply with new environmental policies. Existing resources that face mandatory capital expenditures to comply with environmental regulations are eligible to include these costs in the offers. These resources include an adder in their capacity offer price equal to the amortized project expense "reasonably required to enable a Generation Capacity Resource ... to continue operating...."[37] This "Avoidable Project Investment Recovery Rate" allows coal plants facing the new utility MACT/CAIR NO_x requirements to reflect the costs of compliance into their BRA offers. Because of the resulting higher offer prices, those offers will only

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ir.net/phoenix.zhtml?c=103361&p=irol-newsArticle&ID=1443628&highlight; "Planning for an Uncertain Future Case Study: Replacing Coal Units with Gas," Presentation at 2010 NARUC Annual Meeting, Sam Walters, Progress Energy, November 2010.

[36] Delivery Years begin on June 1 of a year and continue to May 31 of the following year. Hence, the "2012–2013 BRA," conducted in May 2009, secured capacity commitments for the twelve months beginning June 1, 2012.

[37] PJM Tariff, Attachment DD, § 6.8(a).

clear the BRA if they are the most economic alternative resource to satisfy either local or aggregate reliability needs.

RPM's facilitation of economic environmental upgrades was demonstrated when Maryland's *Healthy Air Act*[38] required substantial reductions in NO_x, SO_2, and mercury emissions from large coal-burning power plants beginning in 2010. Owners of the Maryland plants faced a choice similar to that under utility MACT: retrofit the existing facilities to comply, or shut them down. The cost of retrofitting was very high: at Mirant's plants alone, the publicly stated cost was $1.67 billion.[39] The cost of these retrofits was directly reflected in capacity offers for the 2009–2010 Delivery Year (when the *Healthy Air Act* reductions took effect) and contributed to an increase in the capacity price in Maryland.[40] These higher capacity prices, which were necessary to maintain local reliability, imposed an obligation on owners of these coal-fired plants that cleared to undertake those upgrades, funded by the higher capacity payments pledged in the future.

If an offer containing the retrofit recovery cost clears the RPM auction, the resource owner is required to make those upgrades. If it does not clear the RPM auction, and instead a less expensive resource is available to meet the region's capacity needs, the resource owner is free to file a deactivation request and retire the unit at the beginning of the Delivery Year covered by the BRA in which it did not clear.[41] The forward nature of the RPM auction provides advance notice that will help the resource owner and the RTO facilitate a smooth transition to a cleaner fleet.

Importantly, the RPM market furnishes locational capacity price signals, with premiums paid in areas with more critical resource adequacy needs, or with more costly resources available for providing resource adequacy. This locational aspect is significant in that capacity must be deliverable to load to maintain reliability. Due to limitations of the transmission system, some amount of capacity must be located near load centers. Without the locational aspect of the market, local resource adequacy needs might not be satisfied, as market-wide prices would not send price signals to support supply in the areas where it is most needed.

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[38] Annotated Code of Maryland, Environment: Title 2, Ambient Air Quality Control; Subtitle 10, Health Air Act; Sections 2-1001–2-1005.

[39] Power-Gen Worldwide, "FGD Systems Start Operating at 7 Mirant Coal-Fired Units," December 21, 2009, *available at*: http://www.powergenworldwide.com/index/display/articledisplay/371998/articles/power-engineering/projects-contracts-2/2009/12/fgd-systems-start-operating-at-7-mirant-coal-fired-units.html

[40] PJM Market Monitoring Unit, "Analysis of the 2009–2010 RPM Auction," pp. 25–26, *available at* http://www.monitoringanalytics.com/reports/Reports/2008/20092010-rpm-review.pdf

[41] Although this is true as a general matter, in rare cases the generator may provide some location-specific reliability service, such as local-area voltage support, that may require transmission upgrades or other remedies before the unit can be deactivated.

PJM's RPM market has been a success at incenting both new generation resources and new load management. PJM reported that "[o]ver the period covering the first seven RPM Base Residual Auctions, 11,582 MW of new generation capacity was added, which was partially offset by 7,185 MW of capacity derations or retirements over the same period. Additionally, 12,967 MW of new Demand Resources were offered over the last seven auctions, an increase of more than 10,000 MW over that period, and 733 MW of new Energy Efficiency resources were offered in the 2013/2014 auction. The total net increase of installed capacity in PJM over the period of the last seven RPM auctions was 17,887 MW."[42]

In addition to RPM helping ensure adequate resources, RTOs also have market rules that can mitigate any reliability impacts of retirements. For example, PJM conducts reliability impact studies for all units that announce retirement, and requests that those identified as needed for reliability temporarily operate past their planned retirement date pursuant to "reliability must run" (RMR) agreements. To minimize any adverse environmental impacts, RMR agreements can be structured to limit a unit's operations for reliability purposes only. For example, Exelon Generation recently coordinated with PJM and the Pennsylvania Department of Environmental Protection to negotiate a consent decree and operating procedures related to an RMR agreement for its two retiring coal units, which require the units operate for reliability purposes only.[43]

Furthermore, transmission owners in RTOs have an ability to proactively manage long-range reliability issues relating to expected retirements. For example, Commonwealth Edison (ComEd), the local transmission owner in Chicago, proactively filed an application with the Illinois Commerce Commission[44] seeking permission to enhance its transmission system. In its application, ComEd noted the identified upgrades would be required to maintain system reliability in the event that two of Midwest Generation's at-risk coal units, Fisk and Crawford, were to retire.[45]

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[42] http://www.pjm.com/~/media/markets-ops/rpm/rpm-auction-info/2013-2014-base-residual-auction-report.ashx, p. 14.

[43] The PJM Operating Procedures, which contain a copy of the consent decree, are posted at PJM's website at http://PJM.com/planning/generation-retirements.aspx.

[44] ICC Docket No. 10-0385; Commonwealth Edison Company; Application for authorization under Section 4-101 of the Illinois Public Utilities Act ("Act"), 220 ILCS § 5/4-101, or alternatively, for a Certificate of Public Convenience and Necessity, pursuant to Section 8-406 of the Act, to install, operate and maintain two new 345,000 volt electric transmission lines in Cook County, Illinois; filed June 11, 2010.

[45] Direct Testimony of Thomas W. Leeming, p. 2, lines 25-35.

Vertically Integrated Markets

In states with vertically integrated utilities, there is a legal obligation to serve load and state regulatory commissions require long-range, integrated resource plans (IRPs). For example, utilities in the VACAR region for which we project a possible 6,322 MW capacity shortfall, are state-regulated. A review of the IRPs of the major VACAR utilities[46] reveal that these companies plan to add about 2,800 MW of new gas-fired capacity before 2015, capacity we did not include in our capacity additions because the plants are not sufficiently advanced to pass our very conservative screen. Yet, these planned resources, such as Dominion's 1,100 MW Warren County Combined Cycle Plant (in the permitting phase), have state regulatory backing, which assures cost recovery. In addition, these IRPs include about 1,000 MW more load management than is shown in NERC's 2010 Summer Assessment. Thus, 3,800 MW of the potential 6,322 MW need in VACAR is already planned for under the required IRPs.

Statutory and Regulatory Safeguards

In the unlikely event that the mechanisms discussed in this paper are inadequate to mitigate reliability impacts of retirements, governmental and regulatory agencies have authority to grant delays or waivers of compliance in certain circumstances. First, EPA can exercise its statutory authority under the CAA to grant, on a case-by-case basis, extensions of time to complete pollution control installations. Under the CAA, the EPA can issue permits that grant a one-year extension beyond the normal statutory three-year period, "if such additional period is necessary for the installation of controls," providing a total of four years for compliance with the regulations.[47] Second, the President of the United States is authorized under Section 112 of the CAA to grant compliance extensions of up to two years on a case-by-case basis after a demonstration that the technology to implement utility MACT is not available. Finally, in certain emergency circumstances, the DOE has the authority under Section 202(c) of the Federal Power Act to override requirements under the CAA.[48]

Conclusions

To analyze the electric system reliability impacts of predicted coal-fired plant retirements on an RTO, NERC regional, and NERC subregional basis, we performed a detailed system modeling analysis of the Eastern Interconnection based on an aggressive policy representation of the proposed and forthcoming EPA air regulations. We conclude that implementing EPA air regulations will not compromise electric system reliability. Rather, reliability can be maintained in all RTOs, and NERC regions and subregions through coal to gas conversions, new gas-fired generation, expansion of load management programs, and established market and regulatory safeguards. Of the areas we analyzed - 5 RTOs, 6 NERC Regions, and 7 NERC subregions - we project that after predicted coal retirements, most still have capacity surpluses. At the NERC regional level, we predict that two regions will have de minimis shortfalls (relative to resource adequacy requirements) and another region will have a modest shortfall. We predict that three subregions within SERC will have shortfalls. One such shortfall is de minimis, one is modest, and only one area, the VACAR subregion, has a larger shortfall. But notably, VACAR's 6,322 MW shortfall, only 1,100 MW of which are attributable to EPA's forthcoming air pollution regulations, can be easily managed: over half of the shortfall is already planned for under the required IRPs (new capacity and load management), and the rest, approximately 2,500 MW, could be addressed through construction of new gas-fired power plants or incremental load management.

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[46] Dominion, Duke-North Carolina, Progress-North Carolina, Santee Cooper, and SCANA.

[47] CAA Sec 112(i)(3)(B).

[48] See footnote 12 for an illustration of such a remedy.

Also significantly, the industry has consistently proven its ability to expand capacity relatively quickly to meet increased demand. In nine of the twelve five-year periods from 1949 to the present, at least 39 GW of new capacity was added nationwide, with 177 GW of mostly gas-fired capacity, or more than four times the projected US coal retirements, added in the 1999-2004 period alone. Futhermore, although projected retirements may cause some localized reliability issues, RTOs and state regulators are well-equipped to deal with any that arise.

Appendix A: Background Information on Reliability

Appendix B: Modeling and Methodology

Appendix C: PJM RPM Market Example

Appendix D: Detailed Calculations Tables

Appendix A: Background Information on Reliability

Generation resource adequacy is an integral part of reliability. In this section, we discuss how different areas of the country maintain resource adequacy. This background is important to our examination of the utility MACT/CAIR NO_x policy's potential effect on regional reserve margins to assess whether unit retirements could adversely affect electric reliability.

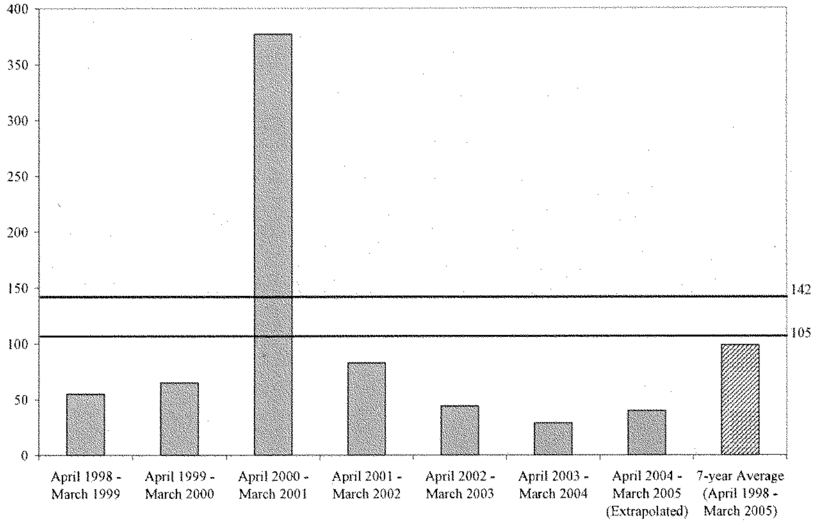
With a few notable exceptions, the electric utility industry has maintained an extremely high level of reliability. The first major reliability incident was in November 1965. Thirty million people lost power in the northeastern United States in what came to be called the "Northeast Blackout." In response, in 1968, NERC was established by the industry. Nine regional reliability organizations were formalized under the NERC umbrella, with regional planning coordination guides and operating criteria.

For almost 40 years there were no major outages in the eastern US, until August 2003, when 50 million people lost power in Northeastern and Midwestern US and Ontario. As a direct consequence of this blackout, in 2007, compliance with NERC standards, which had been voluntary, was made mandatory by the FERC. These standards primarily relate to short-term system operation and transmission system planning, with little reference to generation adequacy, which largely is left to RTOs, states and other entities.

Importantly, the two major eastern outages were not due to a lack of generation resources; both were triggered by transmission failures. The 1965 Northeast Blackout began when an improperly set protective relay shut off power after a small surge in upstate New York. The 2003 blackout occurred when high-voltage transmission lines in Ohio contacted overgrown trees. In its 2003 summer assessment, NERC reported that the NERC subregion where the transmission outage was triggered had a 28.3% reserve margin, which meant that available reserve generating capacity was significantly more than adequate.

It is possible to have a robust transmission system but have less than adequate reliability because of inadequate generation. Although resource shortages have rarely led to load shedding, it did occur in California in late 2000 and early 2001. Despite an installed capacity target in California, there was no mandate to maintain a required level of capacity. When California restructured its generation sector in 1996, it was assumed that energy prices would rise to the level needed to support new entry by independent power producers in time to maintain planning margins. While the California economy boomed, electricity demand grew rapidly, but little new generation was built because energy prices remained low and there was no other mechanism to provide ample revenue to support new entry. In fact, prices (unmitigated) would have had to rise to the high levels seen in the 2000-2001 crisis period to have provided sufficient revenue for a generator. But prior to May 2000, the California ISO market price signals were well below what a new entrant needed, and the futures markets for power were also quite weak. As a result, by 2000, available generation was well below what was required to maintain reliable service, and brownouts and blackouts occurred. Figure 5 below, which is from the FERC testimony of Dr. William Hieronymus of CRA, makes this point quite forcefully. The chart shows that energy prices both before and after the April 2000–March 2001 period were well below the $105-142/kW-year mark needed to finance an efficient new combined-cycle unit. Consequently, most merchant plant investors avoided California, and the merchant capacity that was added did not come online until after the crisis.

Figure 5. Margins Earned by Hypothetical New Combined-Cycle Unit Based on Unmitigated Prices ($1998/kW)



Source: Testimony of William H. Hieronymus in EI03-180-00, *et al*, May 13, 2005.

As discussed in the report, unlike in California, mechanisms do exist in the Eastern Interconnection —namely, capacity markets and state regulation—to ensure that ample capacity will be available to maintain reliability. Consequently, a California-type crisis triggered by inadequate supply resources is far less likely in the Eastern Interconnection, provided that unit retirements are foreseen with sufficient notice to bring any required replacement resources into service.

The Eastern Interconnection consists of a large portion of the US and Canadian transmission system east of the Continental Divide, with the exception of a large portion of Texas, which is a separate interconnected system (see Figure 3). Today, the Eastern Interconnection consists of six NERC regional reliability organizations and five RTOs. All Eastern Interconnection transmission and generation is in one of the NERC regions, but only a portion of the generation and transmission is in an RTO. Although the NERC regions have responsibility for monitoring and enforcing NERC reliability standards in practice, the RTOs are ultimately responsible for taking the actions needed to ensure reliability in their control areas.

The RTOs conduct reliability impact studies for all units that announce retirement, and can offer RMR agreements to those units needed to temporarily operate past their planned retirement date to maintain reliability. For example, on December 2, 2009, Exelon Generation submitted a notice to retire four coal units at its Cromby and Eddystone stations in Pennsylvania. PJM studied the transmission system impact and determined that these retirements would adversely affect reliability until certain upgrades to the transmission system were made. PJM asked Exelon Generation to continue to operate one unit at each station beyond May 31, 2011. PJM and Exelon negotiated an RMR rate under the PJM Tariff, and FERC approved the RMR rate subject to hearing.[49]

Additionally, three of the RTOs (ISO New England, the New York ISO, and PJM) have established capacity markets to ensure that adequate capacity is online, and the Midwest ISO and SPP are moving to establish their own capacity markets as well.[50]

These capacity markets are designed to ensure that adequate capacity is online to meet load and that new entry occurs when and where needed. These payments can be substantial. For example, for the 2013/2014 period, a capacity resource in PJM outside of MAAC[51] will receive $27.73/MW-day ($10.12/kW-year), while resources in MAAC will receive from $226.15/MW-day ($82.54/kW-year) to $247.14/MW-day ($90.21/kW-year), depending on the location within MAAC. Because this forward market provides a signal three years in advance developers can see the need and capacity revenues they will receive early enough to develop new resources or, conversely, if capacity revenues will be inadequate to support existing resources, allowing for an orderly deactivation of these uneconomic resources.

Forward capacity markets, like those in PJM and ISO New England, therefore serve a dual purpose with respect to existing unit retirements. Existing units facing high costs, including capital costs related to environmental upgrades, may find themselves priced out of the market if that capacity is no longer needed for reliability; consequently, these "at risk" generators may choose to retire rather than earn capacity payments insufficient to cover their costs. If that capacity *is* needed for reliability, however, the capacity market provides a transparent price signal, set by the going-forward costs of existing units (including, when needed, capital expenses for environmental upgrades). If the all-in, levelized cost of new capacity resources is below the going-forward costs of these highest-cost existing generators, then the older resources will be displaced by the more economic new units.

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[49] http://pjm.com/~/media/documents/ferc/2010-filings/pjmmotion.ashx

[50] The Midwest ISO already conducts monthly capacity auctions through which it enforces resource adequacy standards, pursuant to Module E of its tariff.

[51] MAAC is the portion of PJM that corresponds to what used to be the NERC Mid-Atlantic Area Council. The term MAAC is still used by PJM to describe the eastern part of the PJM system.

The New England ISO, the New York ISO, and PJM capacity markets selectively draw from a common set of objectives:

- Price signals for new capacity that are observable or reasonably predictable several years in advance of actual need.[52]
- Demand curves or other mechanisms that provide stability and lead to price formation that will set the price at the net cost of new entry (Net CONE) when capacity levels are at the target reserve margin, but will be higher than Net CONE if capacity is below the target reserve margin and less than Net CONE if capacity is above the target reserve margin.[53]
- Locational price signals.

The locational aspect is quite important since in order to maintain reliability, capacity must be deliverable to load. Given limitations of the transmission system, some amount of capacity typically must be located near load centers.

In PJM there are 24 load delivery areas (LDAs), each of which can be a separate zone in PJM's RPM capacity market. The zones (consisting of LDAs) are determined by the level of imports needed to maintain a predetermined level of reliability. Capacity prices are then set at levels in each LDA that ensure not only that the overall regional planning reserve margin is met, but that the locational resource requirement of each LDA is also satisfied. Consequently, it has generally been the case that capacity prices along the Eastern seaboard, from New York City to Washington, are much higher than capacity prices in the Midwest, reflecting both the constrained west-to-east transmission system and the higher going forward-costs of generators in the east—in some cases, costs directly attributable to compliance with state air emissions regulations.[54]

Non-RTO regions, primarily in the Southeast, as well as many states in RTO areas, particularly the Midwest ISO and SPP, are served by vertically integrated utilities, municipal systems, cooperatives, and federal systems. State public utility commissions (or other regulators) set rates and allow regulated utilities to include new capacity in rate base after a demonstration that this new capacity is needed and a prudent investment. To establish the need and prudency of the investment, regulated utilities typically prepare IRP forecasts. These forecasts include future load growth and capacity online that together specify the need for investment in generation and transmission, and preferred solutions. State regulators then act to approve major capital projects and set regulated retail rates to cover direct costs plus a return on invested capital. While this centralized approach to capacity expansion has generally ensured that the utility maintains sufficient capacity reserve margins, many states' legislators and regulators found that the technological and other risks placed onto ratepayers would be better borne by independent power producers.

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[52] Although the NYISO does provide the same three-year forward pricing as the PJM and ISO-NE markets, the relative price stability and predictability created by the administrative demand curve used in the capacity market provides greater guidance to investors than, for example, the month-to-month pricing in the Midwest ISO.

[53] The ISO-NE Forward Capacity Market does not have an administrative demand curve *per se*, but has other design features intended to stabilize the capacity price near the Net CONE value.

[54] The PJM Independent Market Monitor noted that the high capacity prices in Southwest MAAC were linked to bids that included capital cost recovery for compliance with Maryland emissions laws.

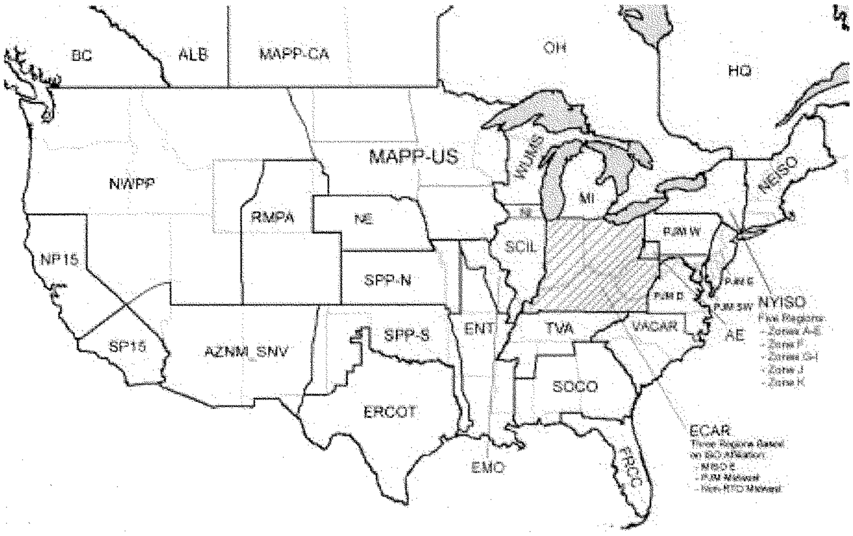
Appendix B: Modeling and Methodology

Estimating Retirements

CRA used its NEEM model to estimate coal unit retirements under the utility MACT/CAIR NO_x policy representation described in the main body of this paper. NEEM optimizes generation operation in each major region in the US, taking into account power transfer limits among regions. NEEM optimizes retirements, unit environmental retrofits, and new capacity additions by region over a 60-year period, taking into account the operating and cost characteristics of existing capacity and the capital and operating costs of potential new capacity.

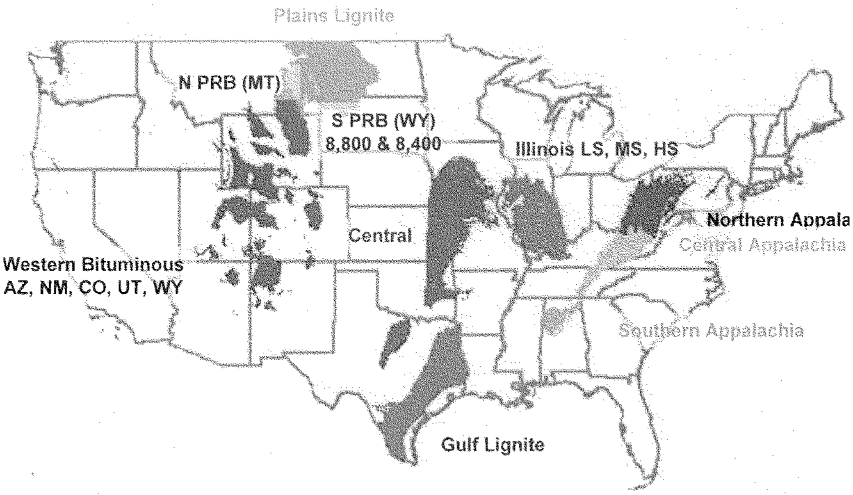
NEEM models the North American electric system as 39 regions that are connected by a network of transmission lines with region-to-region limits and, in some cases, joint import and export limits as shown in Figure 6.

Figure 6. NEEM Regions



Coal Supply - NEEM models coal supply from 23 individual curves representing distinct domestic production areas, Latin American imports, and different coal qualities (sulfur and Btu). See Figure 7 for a description of NEEM's coal supply regions.

Figure 7. NEEM Coal Supply



Pollution Control Retrofits - Coal units in NEEM can install pollution control retrofits based on economics. Control technologies are available for SO_2 (FGD), NO_x (SCR, SNCR), and mercury (ACI + fabric filter, or simply ACI if the unit already has a fabric filter). Each coal unit in NEEM is given a base Fixed O&M (FOM) cost, which is a function of its age and the combination of any existing emissions controls on the unit.[55]

Future retrofits (planned or economically determined by NEEM) result in emissions rate reductions, additional capital expenditures, an incremental FOM adder, an incremental VOM adder, and possibly heat rate and capacity penalties. The capital costs and incremental FOM for FGDs are based on Sargent & Lundy (August 2010).[56] Capital costs and incremental FOM for mercury controls are based on Cichanowicz (July 2006;

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[55] EPA IPM Base Case Assumptions, EPA IPM Base Case v4.10, Chapter 4: Generating Resources, Table 4-9. (Based on FERC Form 1.)

[56] Sargent & Lundy, "IPM Model - Revisions to Cost and Performance for APC Technologies: Wet FGD Cost Development Methodology," August 2010, Table 1.

January 2010).[57] The incremental VOM for new and existing retrofits are also based on the aforementioned documentation.

Load Forecast - NEEM is a load-duration curve model. Load forecast assumptions in NEEM are derived from a combination of 2009 FERC 714 filings and 2010 ISO load forecasts (PJM, MISO, ISO-NE); minor adjustments were made for non-filing entities and some cooperatives. Load forecasts at the planning area level are aggregated to the NEEM-regional level and sorted into three seasons and 20 load blocks. Peak energy forecasts are similarly aggregated and peak coincidence factors are based on 2006 FERC 714 hourly data and 2006 ISO hourly reporting.

Fuel Prices - Natural gas and fuel oil delivered-price forecasts are based on a combination of NYMEX futures and AEO 2010 price forecasts. August 2010 NYMEX Henry Hub futures prices are blended into a longer-term AEO 2010 forecast before 2015. Delivered prices for generating units in each NEEM region are estimated using historically estimated basis differentials. Natural gas prices in NEEM vary seasonally and fuel oil prices vary annually.

New Capacity - In addition to simulating retirement of existing generators, NEEM simulates the deployment of new generating capacity to replace retirements and to meet growth requirements. New generating technologies available in 2015 include fossil units such as advanced conventional coal, natural gas combustion turbine, natural gas combined-cycle, and coal integrated gasification combined-cycle (IGCC). Renewable units such as wind turbines, solar – photovoltaic, solar – concentrated solar power, landfill gas, biomass, and geothermal are also built by the model based on economics and local and regional renewable electricity standards. Capital costs and operating characteristics for new generating capacity are primarily based on EIA Annual Energy Outlook 2009 with some CRA adjustments (e.g., transmission adders). As discussed below, we do not use NEEM's economic new builds directly in our reliability analysis.

Estimating Reliability Impacts

CRA used the following approach to estimating reliability impacts by NERC region:

1. We started with the NERC 2010 Summer Assessment's Total Internal Demand. We also calculated the difference between Total Internal Demand and Net Internal Demand as an estimate of demand side resources (in 2010 and 2015).

2. Using the 2010 Total Internal Demand, we applied growth factors to obtain the 2015 Total Internal Demand estimates by NERC region. We then subtracted the demand-side resource estimates obtained above to arrive at 2015 Net Internal

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[57] J. Edward Cichanowicz, "Testimony of J. E. Cichanowicz to the Illinois Pollution Control Board: A Review of the Status of Mercury Control Technology," July 28, 2006; J. Edward Cichanowicz, "Current Capital Cost and Cost-Effectiveness of Power Plant Emissions Control Technologies," January 2010.

Demand. The growth factors applied to Total Internal Demand are based on the 2010–2015 growth in Total Internal Demand from the 2009 NERC Electricity Supply & Demand (ES&D).

3. The 2015 capacity online estimate was calculated by taking the certain-existing capacity from the NERC 2010 Summer Assessment and adding planned new builds and subtracting planned retirements. The data source for new builds and retirements is Energy Velocity. The new build status categories considered were, conservatively, "under construction" or "testing." For retirements, conservatively, all status categories were considered except for "canceled."

4. Net firm transactions were then deduced from the NERC 2010 Summer Assessment and added to the 2015 capacity online estimate.

5. The 2015 resource adequacy surplus (or shortfall) was then calculated using the capacity online estimate and the Net Internal Demand estimate. This resource adequacy surplus (or shortfall) estimate is prior to the inclusion of our coal retirement estimates.

6. We then included modeled coal unit retirement estimates from NEEM and recalculated the 2015 resource adequacy surplus (or shortfall). We did not add in NEEM's economic new additions.

7. We then included planned additions that are less conservative, including those in the "permitted" or "site prep" status categories. These are new additions that are less certain than those under construction but nevertheless could occur fairly quickly as they face no significant regulatory hurdles. We recalculated the 2015 resource adequacy surplus (or shortfall).

8. Finally, we reported the forecasted number of percentage points above or below reserve margin in 2015.

Appendix C: PJM RPM Market Example

To illustrate how retrofit and replacement decisions for existing coal units will be guided by the RPM market, CRA has examined how the LDAs that have been modeled in recent RPM auctions would be affected by the retirements identified in the analysis described earlier in this report. Specifically, the analysis estimates the reliability requirements and available resources in each LDA for the BRA for the 2015/16 Delivery Year, which is the first auction for which regulations would be expected to affect capacity resource offers.

Table 5[58] shows the reliability requirements and available resources for the PJM RTO and each LDA that was included in the most recent BRA, conducted in May 2010 for the 2013/14 delivery year. The reliability requirements for 2013/14 are shown, along with the quantity of resources that were offered into the BRA. The projected supply and demand for 2015/16 is also shown, assuming that the reliability requirements will escalate with projected load growth and that the coal-fired capacity will be retired as projected under our analysis of the utility MACT/CAIR NO_x policy.

The expected retirements from the utility MACT/CAIR NO_x policy includes 7,529 MW (on a UCAP basis, which reduces the capacity of each resource to reflect the forced outage rate) of coal-fired capacity within the PJM RTO footprint. Of the total PJM capacity, 1,744 MW is located in the AEP zone, which does not participate in the RPM market, leaving 5,785 MW of planned retirements that will affect the RPM market clearing directly.

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[58] Table 5 shows the supply and demand balance in terms of the unforced capacity (UCAP) metrics used by PJM. In addition, the planned retirements shown are only those from the 2013/14 auction to the 2015/16 auction.

Table 5. Impact of Projected PJM Coal Retirements 2015/16 Base Residual Auction

	2013/14 Capability Year			Retirements		2015/16 Capability Year		
LDA	Available Resources	Reliability Requirement	Surplus/ (Shortfall)	Planned	Economic	Available Resources	Reliability Requirement	Surplus/ (Shortfall)
RTO (with AEP)	186,588	169,799	16,789	825	7,061	178,703	174,843	3,860
RTO (excluding AEP)	160,898	146,239	14,659	69	5,425	155,404	150,583	4,821
MAAC	72,798	71,451	1,347	-	1,503	71,295	73,538	(2,243)
SWMAAC	18,493	17,502	992	-	294	18,199	18,038	162
PEPCO	9,772	9,250	522	-	152	9,620	9,460	160
EMAAC	40,102	39,472	630	-	302	39,800	40,573	(773)
PSEG	13,902	13,099	803	-	-	13,902	13,421	480
PS-North	6,743	6,208	535	-	-	6,743	6,361	383
DPLS	3,735	2,933	802	157	15	3,563	3,016	547

All values in MW (UCAP)

Overall the PJM RTO has sufficient capacity to replace retirements, but the impact varies by subzones within the broader PJM region: in 2015/16, given current transmission limits,[59] more resources than are required to meet the LDA reliability requirement are available for each LDA except MAAC and Eastern MAAC. As long as the policy is known with sufficient lead time to allow new resources to be offered into the BRA, RPM will provide a transparent market signal for new entry. In fact, for the MAAC LDA, which would need just over 2,000 MW of new capacity under the retirement scenario, 3,700 MW of new capacity is already under development, of which just over 1,000 MW is permitted and another 600 MW is in the permitting process. Additional projects could be developed if needed between now and the time of MACT implementation.

In addition to identifying need, RPM provides a price mechanism to support resource adequacy. In the Eastern MAAC and MAAC LDAs, RPM prices will, by design, rise to levels that can support new entry, or if it is more cost-effective, support retrofitting existing coal-fired capacity to be compliant with the utility MACT.

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[59] Planned new transmission such as the PATH, MAPP and Susquehanna–Roseland projects may well impact the locational capacity requirements. In addition, transmission projects can participate in the RPM market and respond to the same price signals.

Appendix D: Detailed Calculation Tables

Table 2. Loads and Resources by 2015, RTO Level

	(NID)	(RRM)	(n)	(p)	(q) Resource Increase	(r) Resource Decrease	(x) = (p) + (q) - (r)	(y) Resource Increase	(z) = (x) + (y)	(A) = (z) - (n)	(d) Resource Decrease	(e) = (z) - (d)	(B) = (e) - (n)	(f) Resource Increase	(C) = (B) + (f)	= [(e) + (f)] / NID - 1 - RRM
RTO	*2015 Net Internal Demand Estimate (MW)	Required Reserve Margin (%)	Required Capacity (MW)	**Certain-Existing Capacity (MW)	***Planned New Additions by 2015 (derated MW), Energy Velocity	# Planned Retirements by 2015 (MW), Energy Velocity	Projected Capacity in 2015 (MW)	++ Net Firm Transactions in 2010 Summer Assess. (MW)	Projected Capacity PLUS Net Firm Transactions (MW), 2015	(A) 2015 Resource Adequacy Surplus / (shortfall) (MW)	Projected Coal Retirements by 2015, due to MACT / CAIR NOx (MW)	## Retirement-Adjusted Projected Capacity PLUS Net Firm Transactions (MW), 2015	(B) Retirement-Adjusted 2015 Resource Adequacy Surplus / (shortfall) (MW)	+ New Additions by 2015 in Permitted Stage (derated MW), Energy Velocity	(C) Retirement-Adjusted 2015 Resource Adequacy Surplus / (shortfall), Reflecting Permitted Builds (MW)	Predicted Percentage Points Above (or Below) Required Reserve Margin in 2015 (%)
PJM	146,441	15.3%	168,846	176,362	5,154	3,454	178,061	-	178,061	9,215	7,529	170,532	1,686	2,350	4,036	2.8%
MISO	91,001	15.4%	105,015	123,821	3,470	203	127,088	-	127,088	22,073	7,074	120,014	14,999	435	15,434	17.0%
New England	26,180	15.0%	30,107	32,229	213	100	32,342	288	32,630	2,523	370	32,260	2,153	1,094	3,247	12.4%
New York	31,803	15.0%	36,573	36,668	1,386	743	37,312	1,580	38,892	2,318	348	38,543	1,970	192	2,162	6.8%
SPP	45,284	13.6%	51,442	49,777	2,407	-	52,184	1,225	53,409	1,966	664	52,745	1,302	102	1,404	3.1%

* "2010 NERC Summer Asssessment Total Internal Demand" PLUS "growth to 2015 implied by NERC 2009 ES&D" LESS "difference between Total Internal Demand and Net Internal Demand according to the 2010 NERC Summer Assessment" (for New England, New York, and SPP). For PJM, the PJM 2013/14 RPM Base Residual Auction Planning Parameters, total RTO load net of load management. For MISO, 2015 Coincident Net Internal Demand, Midwest ISO Transmission Expansion Plan (MTEP) 2009.

** NERC 2010 Summer Assessment for New England, New York, and SPP. PJM: 2013/14 RPM Model existing resource parameters nat FERC 411 purchases and sales; MISO: 2009 Summer Assessment Total July 2009 capacity net of imports/exports.

*** This includes the "under construction" and "testing" categories in Energy Velocity. Renewables have been derated.

This includes all categories of retirements in Energy Velocity except for "cancelled."

++ Firm net imports that count toward reserve margin.

Assume no change in net firm transactions through 2015.

+ Planned new additions that are in the "permitted" or "site prep" status categories.

Table 3. Loads and Resources by 2015, NERC Regional Level

	(NID)	(RRM)	(n)	(p)	(q) Resource Increase	(r) Resource Decrease	(x) = (p) + (q) - (r)	(y) Resource Increase	(z) = (x) + (y)	(A) = (z) - (n)	(d) Resource Decrease	(e) = (z) - (d)	(B) = (e) - (n)	(f) Resource Increase	(C) = (B) + (f)	= [(e) + (f)] / NID - 1 - RRM
NERC Region	***2015 Net Internal Demand Estimate (MW)**	**Required Reserve Margin (%)**	**Required Capacity (MW)**	**Certain-Existing Capacity (MW), NERC 2010 Summer Assess.**	****Planned New Additions by 2015 (derated MW), Energy Velocity**	**# Planned Retirements by 2015 (MW), Energy Velocity**	**Projected Capacity in 2015 (MW)**	**++ Net Firm Transactions in 2010 Summer Assess. (MW)**	**Projected Capacity PLUS Net Firm Transactions (MW), 2015**	**(A) 2015 Resource Adequacy Surplus / (shortfall) (MW)**	**Projected Coal Retirements by 2015, due to MACT / CAIR NOx (MW)**	**## Retirement-Adjusted Projected Capacity PLUS Net Firm Transactions (MW), 2015**	**(B) Retirement-Adjusted 2015 Resource Adequacy Surplus / (shortfall) (MW)**	**+ New Additions by 2015 in Permitted Stage (derated MW), Energy Velocity**	**(C) Retirement-Adjusted 2015 Resource Adequacy Surplus / (shortfall), Reflecting Permitted Builds (MW)**	**Predicted Percentage Points Above (or Below) Required Reserve Margin in 2015 (%)**
FRCC	47,330	15.0%	54,429	52,989	1,550	804	53,735	2,025	55,760	1,331	1,335	54,425	(4)	2,550	2,546	5.4%
MRO	42,681	15.0%	49,083	48,750	885	83	49,553	265	49,818	735	3,640	46,178	(2,905)	377	(2,528)	-5.9%
NPCC	60,894	15.0%	70,028	68,897	1,599	843	69,653	1,868	71,521	1,494	718	70,803	776	1,286	2,062	3.4%
RFC	186,008	15.0%	213,909	217,700	5,175	3,495	219,380	1,900	221,280	7,371	10,306	210,974	(2,935)	2,351	(583)	-0.3%
SERC	213,891	15.0%	245,975	246,535	9,019	3,525	252,029	91	252,120	6,145	12,716	239,404	(6,571)	5,934	(638)	-0.3%
SPP	45,284	13.6%	51,442	49,777	2,407	-	52,184	1,225	53,409	1,966	664	52,745	1,302	102	1,404	3.1%

* "2010 NERC Summer Asssessment Total Internal Demand" PLUS "growth to 2015 implied by NERC 2009 ES&D" LESS "difference between Total Internal Demand and Net Internal Demand according to the 2010 NERC Summer Assessment."

** This includes the "under construction" and "testing" categories in Energy Velocity. Renewables have been derated.

This includes all categories of retirements in Energy Velocity except for "cancelled."

++ Firm net imports that count toward reserve margin.

Assume no change in net firm transactions through 2015.

+ Planned new additions that are in the "permitted" or "site prep" status categories.

Table 4. Loads and Resources by 2015, NERC Subregional Level

	(NID)	(RRM)	(n)	(p)	(q) Resource Increase	(r) Resource Decrease	(x) = (p) + (q) (r)	(y) Resource Increase	(z) = (x) + (y)	(A) = (z) - (n)	(d) Resource Decrease	(e) = (z) - (d)	(B) = (e) - (n)	(f) Resource Increase	(C) = (B) + (f)	= [(e) + (f)] / NID - 1 - RRM
NERC Sub-Region	*2015 Net Internal Demand Estimate (MW)	Required Reserve Margin (%)	Required Capacity (MW)	Certain-Existing Capacity (MW), NERC 2010 Summer Assess.	**Planned New Additions by 2015 (derated MW), Energy Velocity	# Planned Retirements by 2015 (MW), Energy Velocity	Projected Capacity in 2015 (MW)	++ Net Firm Transactions in 2010 Summer Assess. (MW)	Projected Capacity PLUS Net Firm Transactions (MW), 2015	(A) 2015 Resource Adequacy Surplus / (shortfall) (MW)	Projected Coal Retirements by 2015, due to MACT / CAIR NOx (MW)	## Retirement-Adjusted Projected Capacity PLUS Net Firm Transactions (MW), 2015	(B) Retirement-Adjusted 2015 Resource Adequacy Surplus / (shortfall) (MW)	+ New Additions by 2015 in Permitted Stage (derated MW), Energy Velocity	(C) Retirement-Adjusted 2015 Resource Adequacy Surplus / (shortfall), Reflecting Permitted Builds (MW)	Predicted Percentage Points Above (or Below) Required Reserve Margin in 2015 (%)
FRCC	47,330	15.0%	54,429	52,989	1,550	804	53,735	2,025	55,760	1,331	1,335	54,425	(4)	2550	2,546	5.4%
MRO	42,681	15.0%	49,083	48,750	885	83	49,553	265	49,818	735	3,640	46,178	(2,905)	377	(2,528)	-5.9%
NPCC - New England	26,180	15.0%	30,107	32,229	213	100	32,342	288	32,630	2,523	370	32,260	2,153	1094	3,247	12.4%
NPCC - New York	31,803	15.0%	36,573	36,668	1,386	743	37,312	1,580	38,892	2,318	348	38,543	1,970	192	2,162	6.8%
RFC	186,008	15.0%	213,909	217,700	5,175	3,495	219,380	1,900	221,280	7,371	10,306	210,974	(2,935)	2351	(583)	-0.3%
SERC - Central	44,956	15.0%	51,699	49,345	1,871	-	51,216	2,046	53,262	1,563	4,329	48,933	(2,766)	1363	(1,403)	-3.1%
SERC - Delta	30,167	15.0%	34,692	40,172	886	227	40,831	(720)	40,111	5,419	343	39,768	5,077	513	5,590	18.5%
SERC - Gateway	19,883	11.9%	22,250	24,369	1,600	-	25,969	(2,150)	23,819	1,569	641	23,178	929	62	991	5.0%
SERC - Southeastern	52,889	15.0%	60,822	61,779	399	758	61,420	1,007	62,427	1,604	4,407	58,020	(2,802)	2121	(681)	-1.3%
SERC - VACAR	67,838	15.0%	78,014	70,870	4,263	2,540	72,593	221	72,814	(5,200)	2,997	69,817	(8,197)	1874	(6,322)	-9.3%
SPP	45,284	13.6%	51,442	49,777	2,407	-	52,184	1,225	53,409	1,966	664	52,745	1,302	102	1,404	3.1%

* "2010 NERC Summer Asssessment Total Internal Demand" PLUS "growth to 2015 implied by NERC 2009 ES&D" LESS "difference between Total Internal Demand and Net Internal Demand according to the 2010 NERC Summer Assessment."

** This includes the "under construction" and "testing" categories in Energy Velocity. Renewables have been derated.

This includes all cetegories of retirements in Energy Velocity except for "cancelled."

++ Firm net imports that count toward reserve margin.

Assume no change in net firm transactions through 2015.

+ Planned new additions that are in the "permitted" or "site prep" status categories.

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Senator Thomas Carper
513 Hart Building
Washington, DC 20510

November 3, 2010

Dear Senator Carper:

Thank you for your letter of October 6, 2010 requesting the Institute of Clean Air Companies' (ICAC) insights and perspective regarding the questions of labor availability and the capacity of the electric power industry to install air pollution control systems on a timely schedule and the types of jobs these installations create. As you recognize in your letter, this is not a new concern. In fact, industry stakeholders raised this exact concern when EPA proposed the NOx SIP Call rule in 1998 and, again, when EPA proposed the Clean Air Interstate Rule (CAIR) in 2005. Notably however, these were concerns raised primarily in advance of the finalization of rules, and in both cases proved unfounded as the stationary source air pollution control and measurement (APC) industry satisfied demand for labor and other resources placed upon us and related industries. These concerns and doubts are being raised again; however, based on a history of successes, we are now even more resolute that labor availability will in no way constrain the industry's ability to fully and timely comply with the proposed interstate Transport Rule and upcoming utility MACT rules. Contrary to any concerns or rhetoric pointing to labor shortages, we would hope that efforts that clean the air also put Americans back to work. We appreciate your efforts to more fully understand this issue and we offer the following responses to the specific questions you raise:

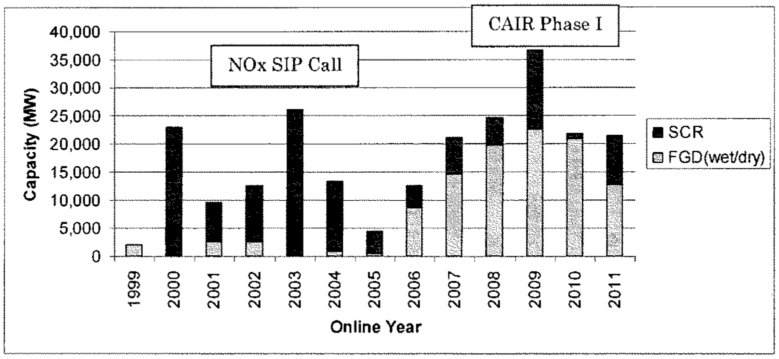
- The APC Industry is able to meet future demands for emission control technology due to our overwhelming experience in meeting requirements for selective catalytic reduction (SCRs) and flue gas desulfurization (FGDs) under the NOx SIP Call and CAIR.
- Less resource and time-intensive technologies are available to be quickly deployed offering the electric generating industry the needed flexibility to comply with the proposed Clean Air Transport Rule and the upcoming utility MACT. For example direct sorbent injection (DSI) and dry scrubbing technology installation times are approximately 12 and 24 months, respectively.
- The design and construction of NOx, SO_2 and HAPs control technologies require engineers, skilled craft labor such as boilermakers and creates upstream and downstream employment and economic benefits.
- We estimate that over the past seven years, the implementation of CAIR Phase 1 resulted in 200,000 jobs in the APC industry.

Is labor availability likely to constrain the industry as it seeks to comply with the interstate transport and utility MACT rule?

The simple answer is that labor availability has never jeopardized overall industry compliance requirements, nor is there any reason to assume that it would prevent the power generation industry from effectively complying in a timely way with requirements. As an industry, we respond to whatever demand for products and services is placed upon us by affected industries complying with requirements. The corollary to this response is that the APC industry has proven, particularly in recent years, the dynamic nature of ours and related industries in meeting demand from the electric power generating industry. This has been demonstrated by repeatedly satisfying rapid and substantial increases in demand for services and products, working effectively with end-users to efficiently deploy resources to meet compliance deadlines, innovating then bringing those innovations quickly to market, and relying on inherent competitiveness within the industry to bring an ever broader range of economically reasonable solutions to our customers. The variable nature of our industry, including supporting and related industries, now finds us at a point where demand for products and services is low, so we are well-positioned to meet any new demand.

We are extremely confident in the ability of our industry to deliver and satisfy, as we have so successfully in the past, the labor, materials and resources needed to meet the demand. Labor availability did not constrain the electric power industry's ability to comply with CAIR and the NOx SIP Call. We based this observation on (1) recent and past decade of industry installation experience, and (2) the extent of controls already installed at existing coal-fired power plants. In addition, there are less capital intensive control technology options available to the industry that can be implemented in a shorter period of time. In these current market conditions the APC industry is in a period of underutilization as compared to the NOx SIP Call and CAIR Phase I years.

Figure 1. Cumulative SCR and FGD Installations by Year



Source: US EPA NEEDs database 4.10 v

Many of the technologies that will be needed to be installed to comply with the requirements of the proposed interstate Transport Rule and the as yet-to-be-proposed utility MACT rule are likely to be the same technologies installed in recent years for other successful and more labor-intensive programs. In fact, over the past decade (as illustrated in Figure 1) our industry has already successfully met the challenge of installing what were substantially new technologies on a significant portion of the electric power industry. These technologies have been refined and are readily available, as are the resources needed to complete their installation. Today more than one-half of the coal-fired electric generation fleet currently operates reliably on some combination of these technologies.

The trend in recent years has been to install the largest and most effective control systems such as FGD and SCR systems, which are also some of the most labor-intensive and time-consuming technologies available. The design and construction of a large 'wet' scrubber system may take 36 months to complete. Wet scrubbers reduce SO_2 emissions by more than 98 percent, and their construction and installation employ several hundred workers. Currently, more than one-half of the coal-fired electric generation capacity of the U.S. operates with FGD systems, with most having been installed over the past decade. We anticipate that FGD control installations from implementing the proposed Transport Rule will be radically less than our recent installation experience under CAIR Phase I. EPA projects that about 14 gigawatts (GW) of coal-fired generating capacity will be retrofitted with scrubbers and less than 1 GW with SCR controls by 2014 to comply with the recently proposed interstate Transport Rule. This is substantially less than what was accomplished under CAIR.

Going forward, ICAC expects a wide range of technologies will be available to provide flexibility for utility compliance strategies. In particular, we expect greater use of both DSI and dry scrubbing technologies, such as circulating dry scrubbers (CDS) and spray dryer absorber (SDA) technology, due to future backend water and disposal requirements. The added advantages of using these technologies are fewer resources required and shorter installation times – 12 months for DSI and 24 months for a dry scrubber. Moreover, the next round of EGU control installations will likely be on smaller coal-fired units, and DSI and dry scrubbing are well-suited to smaller footprints and high-sulfur bituminous coal applications. However, exact technology controls are chosen by electric power generating companies based on final requirements and in a context of multiple market variables.

Recent Industry Experience

The electric power sector has a demonstrated ability to install a large number of complex pollution control systems in a relatively short period of time, while coordinating outage schedules to maintain electric system reliability. Specifically, the industry's recent experience with the CAIR and the NOx SIP Call clearly demonstrates that the industry has more than sufficient capacity to comply with the proposed interstate Transport Rule and upcoming utility MACT rules.

The majority of coal plants have already installed NOx and SO_2 controls. Of the 310 GW of coal capacity in the United States, 170 GW have installed FGD systems and another 55 GW have FGD controls planned. As a result, roughly two-thirds of the existing coal fleet will soon be retrofit with FGD controls. Additionally, about one-half of U.S. coal capacity has installed or soon will be retrofit with advanced NOx controls. Many companies have also installed or optimized existing control systems for mercury reductions in response to state regulations, giving them a jump start on a future utility MACT rule. In the absence of a federal standard, almost 20 states have adopted mercury regulations for coal-fired power plants over the past several years.

Clean Air Interstate Rule. The Clean Air Interstate Rule (CAIR), limiting NOx and SO_2 emissions in the Eastern U.S., created substantial demand for SCR and FGD systems. Between 2008 and 2010, coal-fired power plants added approximately 60 GW of FGD controls and almost 20 GW of SCR controls with a total of 80 GW of FGD controls installed under CAIR Phase 1. CAIR created unprecedented high demand for scrubber components and, lead times on key components, including large recycle pumps, motors, fans, chimney components and construction. Utilities managing large, multiple-scrubber programs, also used the compliance flexibility in the rule to stage and optimize use of personnel and other resources over longer periods than would have been needed were there just one scrubber. It is notable to point out that in a recently presented paper (*Implementation Strategies for Southern Company FGD Projects*; Wall, Healy & Huggins; Power Plant Pollutant Control "Mega" Symposium, September 2010), the Southern Company authors noted that company-wide planning for FGD installations started in 2003, while the CAIR rule was not final until 2005.

Labor limitations are normally cited by the utility industry as the chief limiting factor in undertaking clean air retrofits, and boilermakers, in particular, are cited as the major source of concern because of their specialized skills. Other craft labor, such as iron and steel workers and carpenters, can be drawn from the broader construction industry.

Prior to the implementation of CAIR, EPA and industry stakeholders, such as the Utility Air Regulatory Group, assumed that skilled labor would limit the industry's ability to install air pollution control equipment. However, based on a retrospective review of actual experience by James Staudt, Ph.D., CFA, it was determined that EPA and industry dramatically underestimated the ability of the air pollution control industry to support the utility industry in responding to CAIR[1]. According to Staudt:

> "The assumptions regarding the availability of labor were demonstrated in this White Paper to be too limiting and, by imposing a "hard cap" on labor availability, did not take into account the dynamic nature of U.S. labor markets, which US EPA had acknowledged in the past. Also, assumptions by US EPA and the representatives of the utility industry regarding the timing of orders relative to the finalization of the CAIR proved to be incorrect. As a result, both US EPA and representatives of the utility industry underestimated the ability of the [air pollution control] industry to support the utility industry in its response to the CAIR."

Staudt offers several reasons for why EPA and industry underestimated the capabilities of the labor market: (1) boilermakers will work overtime during periods of high demand; (2)

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[1] "Availability of Resources for Clean Air Projects", James Staudt PH.D., CFA, Andover Technology Partners, October 2010

boilermakers frequently travel to different locations for work, supplementing local available labor; (3) boilermakers work in fields other than power, such as refining/petrochemical, shipbuilding, metals industries and other construction trades, and workers can shift industry sectors with appropriate training; and (4) new workers will enter the field between 1999 and 2001 - for example, in advance of the NOx SIP Call, boilermakers increased their ranks by 35 percent mostly by adding new members.

NOx SIP Call. Between 2001 and 2005, the electric industry successfully installed more than 96 GW of SCR systems in response to the NOx SIP call thus adding NOx controls to roughly one-third of the U.S. coal fleet. During this same time period, the industry was simultaneously adding a record amount of new generating capacity. Between 2001 and 2004, the electric industry built more than 180 GW of new generating capacity, including natural gas combined cycle power plants, coal-fired power plants, and renewable energy facilities.

Alternative Control Options

Much of our discussion has focused on scrubbers and SCR systems that may be used for compliance with the proposed interstate Transport Rule and upcoming utility MACT rule. These technologies may require longer installation times, however, there are other less resource and labor-intensive alternatives that will also be used for compliance. For example, DSI is a technology that reduces SO_2 through injection of trona, sodium bicarbonate or hydrated lime upstream of a particulate control device. DSI does not generally provide the high rates of SO_2 control achieved with a scrubber, but the technology can achieve significant levels of control and can be implemented very quickly—typically within one year. DSI and other dry scrubbing systems also are effective in reducing some hazardous air pollutants that would be controlled under MACT, such as hydrochloric acid (HCl). These systems are likely to preferentially reduce HCl in the flue gas. With regard to NOx control, selective non-catalytic reduction (SNCR) is a widely used technology that can also be implemented in under a year. The levels of NOx control are less than what can be achieved with SCR, but the technology can be installed quickly with fewer labor resources. Again, industry choices prevail in complying with requirements, and there are now approximately 18 GW of generation with SNCR NOx controls.

Even if the upcoming utility MACT were to require the level of control achieved by wet scrubbers, it is unlikely that this technology would then be applied to all of the remaining unscrubbed fleet. We can see that the already installed pollution control systems, along with potential coal plant retirements, will change the future demand for equipment orders. When anticipating outcomes of the yet to be proposed utility MACT, it is important to recognize that wet scrubbers are placed into service to substantially eliminate SO_2 emissions, while the hazardous air pollutants may rely on a different set of less labor intensive technologies. One observation, is that the demand for large equipment orders on the scale of wet scrubbers, may diminish significantly for the near future when driven by the transport rule and utility MACT; and be largely supplanted by alternative technologies that demand less labor and shorter installation time. Historically, affected industry will comply with requirements by utilizing a suite of reasonably economic technology solutions.

It may also be possible to improve the scrubber performance of many older scrubbers that were installed in the 1970's and 1980's. For example, limestone forced oxidation wet scrubber system upgrades at the Vectren Culley Station Units 2 & 3, E.On's Trimble County Unit 1, and Michigan South Central Power's Endicott Station resulted in increased removal efficiencies in the range of 98 percent. Upgrades such as these can also be implemented quickly and at lower cost versus the installation of a new scrubber.

Preserving these compliance alternatives will require that EPA allow a degree of compliance flexibility in its regulatory design. For example, EPA has proposed a hybrid cap-and-trade approach under the proposed interstate Transport Rule that would allow companies to take advantage of these alternative control strategies. In addition, the Clean Air Act MACT program allows a state-granted one year compliance extension, if needed, to complete installation of controls.

What types of engineering and construction skills are required to design and construct NOx, SO2, and HAPs controls?

This is an extremely relevant question, such that dollars spent on air pollution control not only result in avoided health costs including avoided premature mortality, but these same dollars are plowed back into the U.S. economy as good and green jobs. Adding pollution control equipment to existing power plants requires engineers to design the systems and specialized construction labor, particularly boilermakers, to build and install the equipment. When operational, these control systems rely on a continuous supply of manufactured and processed reagents resulting in jobs in related industries. FGD and SCR systems require: (1) construction materials, such as steel plate, alloy steel, fabricated steel components, structural steel, and concrete; (2) engineered equipment and specialty materials, such as slurry pumps, fans, motors and catalyst; and (3) reagents, especially limestone and ammonia. These requirements are examples of direct and indirect employment opportunities resulting from the environmental drives for new and retrofitted air pollution control systems.

Looking back over the past seven years as industry installed SCR and FGD controls in readiness for the CAIR Phase I requirements, we estimate that this work required approximately 200,000 person-year jobs in direct and indirect labor. Specifically, a typical turnkey installation of a 500 MW scrubber is estimated to employ approximately 200 people, with about 80 percent dedicated to construction and 20 percent for engineering and project management[2]. The installation of SCR controls creates a similar number of jobs over a shorter time period and employs a greater number of boilermakers. As we near the end of installing this latest phase of beneficial control projects, these workers are readily available and trained to continue this level of activity.

Boilermakers are an important trade in terms of the installation of pollution control equipment. It is a specialized trade, serving the electric power, refining/petrochemical, shipbuilding, and metals industries, and boilermaker supply, represented by both union and non-union labor, is dynamic in responding to demand. Other crafts can be and have been drawn from the broader construction labor market.

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[2] *Engineering and Economic Factors Affecting Installation of Control Technologies for Multipollutant Strategies*; U.S. EPA; October 2002

We are not aware that engineering labor has ever been raised as an issue that might limit the industry's ability to install air pollution control equipment. There are numerous suppliers of air pollution control equipment. If one supplier becomes busy, there are several other options. Also, companies that are building multiple scrubbers will often adopt standardized equipment designs, reducing the need for engineering support, as supported by Southern Company's experience referenced above.

In addition to the amplified employment demands of major clean air initiatives such as CAIR and the NOx SIP Call, our industry provides a continuous and enduring stream of good and green jobs related to the manufacturing, installation and servicing of air pollution control and measurement technologies.

If labor is in short supply among any of these trades are there actions that we should be taking today in order to ensure that we have the skilled labor needed to comply with the Clean Air Act?

We are extremely confident in the ability of the industry to deliver and satisfy, as we have so successfully in the past, the labor, materials and resources needed to meet the demand. While we do not believe that skilled labor will be in short supply, proactive steps to provide more clarity sooner to industry on the full suite of requirements for air, water, and waste regulations that they are facing, will in turn provide the needed investments and assist our industry in meeting demand. EPA's efforts to move forward expeditiously with the proposed interstate Transport Rule and the upcoming utility MACT rules will be helpful in this regard. We believe early and continuous installations are needed to promote job security in ours and other industries, as well as ensure more efficient application of resources to meet longer term challenges. As discussed throughout our response, labor availability has not and is not an impediment to industry compliance, and we are already at a high level of industry readiness. In closing, ICAC shares your enthusiasm that now is the time "to put American workers back on the job of modernizing our electric generating fleet" and give America the clean healthy air they deserve.

Sincerely Yours,

David C. Foerter, ICAC Executive Director

THOMAS R. CARPER
DELAWARE

United States Senate
WASHINGTON, DC 20510-0803

October 6, 2010

David C. Foerter
Executive Director
Institute of Clean Air Companies
1220 N. Fillmore Street, Suite 410
Arlington, VA 22201

Dear Mr. Foerter,

As you know, the U.S. Environmental Protection Agency (EPA) has proposed regulations to limit electric sector nitrogen oxide (NOx) and sulfur dioxide (SO2) emissions in the Eastern U.S. and will soon be proposing regulations to limit hazardous air pollutant (HAP) emissions from coal- and oil-fired power plants. These regulations are vital for protecting public health and the environment. The proposed transport rule alone is projected to yield $120 to $290 billion in annual health and welfare benefits in 2014.

The Subcommittee on Clean Air and Nuclear Safety held an oversight hearing on EPA's proposed interstate transport rule on July 22, 2010. As part of that hearing, American Electric Power (AEP) introduced written testimony suggesting that labor availability would constrain the industry's ability to install SO2 scrubbers. Similar claims were made when EPA proposed the NOx SIP call rule in 1998 and the Clean Air Interstate Rule (CAIR) in 2005.

In light of the important contributions that your members have made in terms of installing advanced pollution control systems in recent years, I wanted to seek your input and opinion on the issue of labor availability in the pollution control industry. Based on the recent experience of your members, installing scrubbers and other pollution control systems, is labor availability likely to constrain the industry as it seeks to comply with the interstate transport and utility MACT rules? What types of engineering and construction skills are required to design and construct NOx, SO2, and HAPs controls? If labor is in short supply among any of these trades are there actions that we should be taking today in order to ensure that we have the skilled labor needed to comply with the Clean Air Act?

I appreciate your input on this issue. These environmental standards are vital for protecting human health and the environment. They also offer an opportunity to put American workers back on the job modernizing our electric generating fleet. Understanding the ability of labor to provide timely solutions and the capacity of the industry to install the necessary controls will be critical for developing an appropriate regulatory response. With best personal regards, I am

Sincerely yours,

Tom Carper

Tom Carper
U.S. Senator

Mr. UPTON. Thank you. Mr. Kempf?

STATEMENT OF PAUL KEMPF

Mr. KEMPF. Good morning, Chairman Upton and members of the committee, and thank you for inviting me to testify before the committee today.

I am the director of utilities at the University of Notre Dame. The university is a national Catholic university located in Northern Indiana, 90 miles east of Chicago. It has a campus of 1,250 acres with over 140 buildings and a student enrollment of 12,000. Notre Dame was the first university in the U.S. to generate electricity powering lights in its main building shortly after Edison made incandescent lighting practical. The university takes seriously its leadership role in demonstrating stewardship, sustainability and social justice, and therefore seeks to be a leader in all areas, including energy and environment. We are proud of the efforts of our student group, Green ND, and our Office of Sustainability, which have led a number of energy and environmental projects. I appreciate the opportunity to tell the committee about the challenges facing Notre Dame and many other universities across the Nation as we strive to comply with the full range of pending EPA regulations.

We at Notre Dame are most immediately concerned about the suite of four rules known as the boiler MACT rules. These rules will significantly impact many universities, including Notre Dame, which installed their own utility plants to ensure reliable and affordable source of energy for their campuses. These plants are efficient, cost effective, and environmentally sound source of energy for universities. EPA's final rules, however, impose unrealistic and costly requirements that EPA has not justified by corresponding reduction of hazardous air pollutants.

EPA's boiler MACT rules will require significant changes, many of which are not achievable, affordable, or realistic in a timeframe set out by EPA. Improving environment at reasonable cost benefit rates is certainly in all our best interests, but the recent rules will require significant additional capital and operational expenses, assuming compliance is even possible. Compliance testing costs alone will likely increase nearly 20-fold from the expenses based on levels of testing and testing frequency.

Universities face unique challenges in adapting to new rules. Most universities plan over a decade or more. Also, universities are unable to make the types of changes that are options for businesses. We cannot consolidate with other universities, move to a different state, or even overseas. Raising prices for our customers would be a hike in tuition imposed on our students and their families, already stretched by the Nation's struggling economy.

At Notre Dame, we have had a combined heat power system since 1953, one of the first universities to adopt this highly efficient and environmentally conscious means of producing energy. Our CHP system includes three coal fire boilers and three gas and oil boilers, and produces 55 percent of the campus's electrical demand. This fuel diversity offers a hedge against volatility, shortages, and market factors. Regulations should not make it impossible to sustain the reliability and energy security provided by our system.

When the original boiler MACT rule was issued in 2004, the university upgraded its control to achieve that regulation, but then the boiler MACT rule was vacated by the courts. The university was left to decide whether to proceed with its $20 million investment in pollution control equipment, or halt the project. We decided to complete the project and achieve emission reductions. We were left to see whether our new system would be sufficient to comply with the EPA's revised boiler MACT. Now nearly 4 years later, we are faced with a revised rule that is patently different from the original rule, and one that presents uncertain compliance capabilities for our investment. EPA's capital cost estimate for compliance in the '04 rule was estimated at half a million dollars per solid fuel boiler. We spent nearly $7 million to comply with that rule. Now for new boiler MACT, EPA projects capital costs of $2.2 million per unit. With this wide disparity between EPA projected costs and actual costs, it is difficult to plan.

Twenty million dollars in a university setting could provide a full year of tuition for 500 students or a full 4-year scholarship for 1125 students. Before we commit more millions of dollars for resources, EPA should take the necessary time to address the fundamental issues with the rules. We are not publicly funded. These added costs of compliance are directly borne by our students and their families, who are committed to our tradition of offering an excellent education as economically possible to our students. Yet with these rules on the horizon, maintaining that tradition is more challenging than ever before.

Mr. Chairman, thank you for this opportunity to testify before the committee. I welcome any questions you or other Members may have.

[The prepared statement of Mr. Kempf follows:]

Summary of the Statement of Paul Kempf
The American Energy Initiative: Recent EPA Rulemakings Relating to Boilers, Cement Manufacturing Plants, and Utilities
April 15, 2011

- With 1,250 acres and over 140 buildings, Notre Dame is well known for the quality of its physical plant and beauty of its campus.
- Notre Dame takes seriously its leadership role in demonstrating stewardship, sustainability and social justice and therefore seeks to lead by example in all areas including energy and the environment. The University's power plant runs on a highly efficient combined heat and power system, which minimizes environmental impacts.
- Notre Dame is most immediately concerned about the suite of four rules known as the Boiler MACT rules which will impose potentially unachievable standards and will not account for the $20 million investment Notre Dame made to achieve the 2004 Boiler MACT rule.
- These new Boiler MACT rules will significantly impact many universities, including Notre Dame, which, in an effort to ensure a reliable and affordable source of energy for their campuses, installed their own utility plants, many powered by boilers, and most which use coal as the primary fuel.
- We support a extended period of time for EPA to rewrite the rules. We urge EPA to do this in a way that is sensible and achievable and hope that Members of Congress would urge the Agency to move in that direction.
- Once EPA creates a rule that is acceptable and will achieve corresponding hazardous air pollutant benefits, without crippling universities and industry, it is crucial that EPA provide enough compliance time so that we can plan for the changes.
- Universities cannot consolidate with other universities, move to a different state, or expand production overseas. And raising prices for our "customers" would be a tuition hike, imposed on our students and families already stretched thin by the nation's current economic challenges.
- Considering the cumulative effect of all of EPA's pending rules, it is difficult to appreciate just how much it will cost Notre Dame to come into compliance. These added costs of compliance are borne directly by our students and their families.

Statement of Paul Kempf, Director of Utilities, University Of Notre Dame

Before the United States House of Representatives Energy and Commerce Committee, Subcommittee on Energy and Power

Hearing on The American Energy Initiative

April 15, 2011

Chairman Whitfield, Ranking Member Rush, Members of the Committee, Good Morning and thank you for inviting me to testify before the committee today. My name is Paul Kempf and I am the Director of Utilities at the University of Notre Dame in Indiana.

The University of Notre Dame, a national Catholic university, was founded in 1842 by a priest of the Congregation of the Holy Cross. The campus is located in northern Indiana approximately 90 miles east of Chicago Illinois. With 1,250 acres containing two lakes and over 140 buildings with a replacement value in excess of $2.8 billion, Notre Dame is well known for the quality of its physical plant and beauty of its campus. Student enrollment for the 2008-09 academic year was 11,731 students overall and 8,363 undergraduates, representing every region of the United States and many foreign nations.

Notre Dame became the first university in the United States to generate electricity – reportedly up to 10 kilowatts powered eight lights in the Main Building – shortly after Edison made incandescent light practical for use outside the laboratory. In keeping with that historic tradition, the University takes seriously its leadership role in demonstrating stewardship, sustainability and social justice and therefore seeks to lead by example in all areas including energy and the environment. We are proud of the efforts of the campus group "Students for Environmental Action" and of the accomplishments through our Office of Sustainability, which has led these and other energy and environmentally protective approaches:

- Food Services recycles its cooking oil, supports sustainable seafood and coffee production, and purchases 25 percent of its foods locally.
- Reuse programs have kept hundreds of tons of discarded student items and office equipment out of landfills and raised tens of thousands of dollars for local charities.
- Annually we celebrate Energy Week, a student-driven series of films, activities and presentations co-sponsored by Student Government, the Notre Dame Energy Center, the administration's Energy & Environmental Issues Committee and other groups. For one project, students and faculty directly measured the benefit of conserving energy through a "lights out" across campus, demonstrating how just one hour of conserving energy could translate into a savings of $250,000 from the University's annual electricity bill.
- Since 2008 the University has been engaged in an energy conservation measures program, investing over $10M that is projected to reduce campus energy use by over 10%.

The University seeks to strike the appropriate balance of all issues in an effort to achieve the maximum benefit we hope to lead by example for our students who will go forth and become our future leaders.

I appreciate the opportunity to tell the committee about the difficulties that face Notre Dame and many other universities across the nation if the full range of regulations currently pending at EPA are implemented as expected. We are concerned about the cumulative impact of all the rules, which will force a virtual deadlock in our long term planning for our facilities because potential costs could increase exponentially, depending on the various policy decisions made by EPA in the final rules. We at Notre Dame are most immediately concerned about the suite of four rules known as the Boiler MACT rules.[1] The four rules will regulate a range of air pollutant emissions from large industrial and institutional boilers, smaller area sources and solid waste incineration units. In addition, the rules limit what types of materials can be combusted for their energy value in boilers.

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[1] National Emission Standards for Hazardous Air Pollutants for New and Existing Sources for Major Source Industrial, Commercial, and Institutional Boilers and Process Heaters, 76 Fed. Reg. 15608 (Mar. 21, 2011); National Emission Standards for Hazardous Air Pollutants for New and Existing Sources for Area Source Industrial, Commercial, and Institutional Boilers, 76 Fed. Reg. 15554 (Mar. 21, 2011); Standards of Performance for New Stationary Sources and Emission Guidelines for Existing Sources: Commercial and Industrial Solid Waste

These rules will significantly impact many universities, including Notre Dame, which, in an effort to ensure a reliable and affordable source of energy for their campuses, installed their own utility plants, many powered by boilers, and most of which use coal as the primary fuel. These plants have proven to be an efficient, cost effective, and environmentally sound source of energy for universities. EPA's final rules, however, impose unrealistic and very costly requirements that EPA has not justified by corresponding environmental and health protection from reductions of hazardous air pollutants. EPA's Boiler MACT rule will require significant changes, most of which are not achievable, affordable, or realistic in the timeframe set out by EPA.

EPA's definition of a large unit as having heat input capacity greater than 10 MMBtu per hour is also inappropriate and encompasses most university units, including Notre Dame's, without concern for the huge capital expenditures associated with performance testing, fuel sampling and analyses, and add-on air pollution controls. Improving the environment at reasonable cost - benefit rates is certainly in all our best interests, but changes in the recent rules will require significant additional capital and operational expenditures, assuming compliance is even possible. Compliance testing costs alone will likely increase near twenty-fold from our past expense based on increased levels of testing and testing frequency.

We applauded EPA's request to the DC District Court to be given more time to write the Boiler MACT rules, however the request was ultimately rejected by the Court. Now that EPA has announced that it will reconsider the rules, we urge EPA to address what we consider to be fundamental problems with the rules. We support an extended period of time for EPA to propose and adopt sensible amendments of its rules. We hope that Members of Congress would urge the Agency to move in that direction. Once EPA develops rules that reflect corresponding

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Incineration Units, 76 Fed. Reg. 15704 (Mar. 21, 2011); Identification of Non-Hazardous Secondary Materials That Are Solid Waste (76 Fed. Reg. 15456 (Mar. 21, 2011).

hazardous air pollution benefits, without crippling educational institutions and industry, it will be crucial that sources have enough time to plan for the changes and come into compliance.

Universities, although not alone in their difficulties in navigating an increasingly shifting regulatory landscape, face unique challenges in adapting to new rules. First, most universities plan over a range of a decade, at a minimum. It is nearly impossible to account for all of the possibilities in planning at this range when EPA is able to change rules outside of the statutory planning and regulatory cycles established by Congress. Second, universities are unable to make the types of changes that are options for businesses impacted by these rules. We cannot consolidate with other universities, move to a different state, or expand production overseas. And raising prices for our "customers" would be a tuition hike, imposed on our students and families already stretched by the nation's current struggling economy.

At Notre Dame, our facilities have operated as a combined heat and power (CHP) system since 1953, being one of the first adopters of this highly efficient and environmentally conscious means of producing energy. Our system provides energy to over 9 million square feet of academic buildings, residence halls, research facilities and public assembly spaces. Using steam-driven turbine generators, the University's system also produces nearly 55% of the campus's electrical demand.

Our CHP system is critical to campus operations, as its optimum performance ensures reliable heating, cooling and power supply to the various laboratories, teaching facilities, and public assembly spaces. In addition to ensuring research and teaching functions continue despite possible grid failure, the University's ability to supply reliable power directly impacts the safety and smooth functioning of daily campus activities of faculty and students.

The inherent design of the University's CHP system results in overall increased efficiency of the integrated energy process as compared with other widely-used heating, cooling and power systems. Stand-alone electricity generation systems have a typical efficiency of 30%. CHP facilities result in typical efficiencies upwards of 60%. Additionally, the improved energy efficiency of the CHP system minimizes environmental impacts, including reduced emissions of air pollutants. It warrants noting that this inherent benefit of CHP does not provide any regulatory consideration as typically rules are based on heat input and give no credit to higher efficiency means of energy production. CHP systems are the most energy efficient, environmentally responsible, fiscally responsible and reliable means of meeting heating, cooling, and power needs for campus applications.

Our CHP system currently includes six boilers of various age and type; each unit has a maximum heat input capacity greater than ten million British thermal units per hour (MMBtu/hr). The boilers are fired using coal, fuel oil and pipeline natural gas. This energy strategy allows valuable capital resources to be invested in our students and faculty, while keeping higher education as affordable as possible, and still providing fuel diversity which offers a hedge against volatility, shortages and other market factors.

Subsequent to the original promulgation of Boiler MACT in 2004, the University set about to add controls to its solid fuel boilers to achieve the regulation. Having been granted a one year compliance extension for adding controls, we targeted September 2008 for our project completion. In 2007, just months before the compliance date for the rule, and as foundations were being placed and equipment was shipping to campus, the former Boiler MACT rule was vacated by the DC Court of Appeals. The University was left to decide whether to proceed with its nearly $20M investment in pollution control equipment or to halt the project. Considering how far along the project was, we decided to continue, complete the project, achieve emissions reductions and await the resulting reissuance of the rule. Having purchased systems guaranteed to achieve the compliance limits of the original Boiler MACT, we were left to wait and see how EPA would revise the Boiler MACT and whether our newly installed systems would be sufficient to comply with the revised standards.

Whether, after large expenditures, we will be able to comply is a significant concern shared by all regulated sources. As technology improves, and major pollutant emission reductions have already been accomplished, regulatory standards are being set at increasingly tighter levels. EPA sets its standards, presumably, at limits based on data that demonstrates the maximum efficiency of control equipment. While this works in theory, actual plant conditions are highly variable, and sources must count on a certain compliance margin between the theoretically achievable limit and the limit that accounts for real life operations at a plant. When EPA removes this compliance margin through unreasonably tight standards based on data that represents only a snapshot in time of emissions, it leaves plants vulnerable to sanctions for failing to meet the standards, despite having installed the most expensive, best available, EPA-recommended control technology.

Now nearly four years later, we are faced with a revised rule that is patently different from the original rule and one that presents uncertain compliance capabilities for our investment. With new limits significantly lower than previously proposed and regulation of more constituent pollutants, we are grappling with what to do next. Having installed baghouses, lime and powdered activated carbon injection systems on our solid fuel fired boiler, we have applied some of the best technology currently available and can only hope that we can find a means of complying.

It is interesting to look back at EPA's cost estimate for compliance with the 2004 rule in light of our actual compliance costs. EPA had estimated that the 2004 proposed rule would impose an overall capital cost on coal-fired sources of $1.6 billion, or an average per-unit cost of $0.5 million. Notre Dame spent $20 million to comply with that rule for its three solid fuel fired boilers. Now, for the recently finalized Boiler MACT, EPA projects overall capital costs for solid-fired units to be $2.2 billion, or an average per unit cost of $2.2 million. Given EPA's consistent undervaluation of the cost to upgrade facilities to meet its standards, we must plan for compliance costs that greatly exceed EPA's projected costs.

It is even more interesting to consider the value of $20 million in a university setting. For $20 million, we could provide a full year of tuition for 500 students, or provide 125 students a full, four year scholarship. Major expenditures for regulatory compliance come at a direct cost of other highly valuable services to our students. There should be no guessing about whether those major expenditures will ensure regulatory compliance and in this context, correspondingly beneficial hazardous air pollutant reductions.

While Notre Dame is a private university, many public universities are bound by their state's legislature to burn coal from their home state as a way of guaranteeing local economic benefit. EPA acknowledges that solid fuels, especially coal, are very heterogeneous and vary in composition by location. Even though EPA acknowledges this variability, there is insufficient flexibility in the proposed rule to account for variability. When some universities are bound by state law to use a specific type of coal, it can be extremely costly to bring their plant into compliance, as they are not allowed to switch to another fuel with different characteristics. This is challenging even for Notre Dame, which is not bound by state law to use Indiana coal; suppliers typically are unable to guarantee that coal content will remain consistent for vast reserves yet to be mined. Additionally, it is possible that affected sources may encounter logistic and economic obstacles in procuring fuel with parameters required for compliance with the proposed Boiler MACT.

I have focused largely on impacts of the Boiler MACT rules because they will have the most immediate and largest impact on our ability to provide reliable, affordable, and efficient energy to our students and faculty. Other rules, however, will also significantly increase our costs or fundamentally change the way that we have responsibly powered our campus for decades. Perhaps one of the most pressing other issues under consideration at the EPA is the regulation of coal combustion residuals as hazardous waste. Should this valuable coal by product, which we can efficiently reuse, be deemed hazardous waste, the disposal of that alone would have an exponential increase on our costs. Currently 50% of our coal ash is reused to produce sandblasting material and 50% is used by a local landfill for infill and cover material, which they use in lieu of topsoil. If coal ash is regulated as a hazardous waste, not only will a program which currently recycles 100% of the coal ash be discontinued, but those regulations would impose new, exorbitant disposal costs for with no additional environmental benefit. We are also greatly troubled by EPA's new SO2 national ambient air quality standards (NAAQS), and the upcoming Ozone NAAQS. These standards, if written and implemented with the same indifference toward certainty of compliance and cost impact, will most surely be another fiscal nightmare for university administrators.

Considering the cumulative effect of all of EPA's pending rules, which will go into effect at approximately the same time, it is difficult to appreciate just how much it will cost Notre Dame to come into compliance. As we are not publicly funded, these added costs of compliance are borne directly by our students and their families. We are committed to continuing our tradition of offering an excellent education as economically as possible to our students, yet with these rules on the horizon, maintaining that tradition is more challenging than ever before.

Mr. Chairman, I thank you for this opportunity to testify before the committee, and I welcome any questions you or other committee members may have.

Mr. UPTON. Thank you. Mr. Walke?

STATEMENT OF JOHN WALKE

Mr. WALKE. Thank you, Chairman Upton and members of the subcommittee. My name is John Walke and I am Clean Air Director and Senior Attorney for the Natural Resources Defense Council, a national public health and conservation organization with 1.2 million members and online activists nationwide.

Power plants, industrial boiler, and cement plants are the largest emitters of mercury and scores of other toxic air pollution in the country today. Mercury is a powerful brain poison that damages the developing brains of children and fetuses, lowering IQs and harming motor functions. These polluting facilities emit many other toxic air pollutants as well that cause cancer, heart attacks, strokes, asthma symptoms, and premature deaths.

Yet these industrial facilities still are failing to comply with basic clean air requirements to reduce their toxic pollution after two decades after passage of the 1990 Clean Air amendments. This inexcusable situation is due to unlawful delays, along with plainly illegal standards by EPA under the prior administration, standards that were overturned in courts by unanimous decision rendered by judges appointed by Republican and Democratic Presidents alike. These delays in court decisions resulted in EPA under the present administration inheriting the obligation to re-propose and reissue standards that comply with the Clean Air Act and protect the public.

Now that EPA has final and proposed mercury near toxic standards for the three industrial sectors at issue today, these standards will deliver enormous benefits and health to the American people. Yet today's hearing is serving as a platform for industry officials to urge the delay of these lifesaving mercury and air toxic standards. Members of this committee in recent days have acknowledged they are crafting plans to delay these generationally important health safeguards.

If there is one thing for you to remember from my testimony today, it is this. Delay would mean more deaths and disease on a truly staggering scale. If these health protections were to be delayed by even a single year, such delay would result in up to 26,000 premature deaths, 16,500 nonfatal heart attacks, 178,000 asthma attacks, 18,000 hospital admissions and ER visits, 1.3 million days when people would miss work or school, and nearly 8 million days when people would restrict their activities.

If delay is pursued, I am unaware of any other proposal or legislation to have been entertained in Congress that would inflict this level of hardship upon the American people's health in a single year. I respectfully appeal to the members of this committee to be straight with the American people about the deadly consequences of delay. The American people deserve to have these choices put in sharp relief. The choice between enforcing the law and securing these tremendous health benefits every year are blocking law enforcement and sacrificing public health.

Americans have a right to understand how many people would be allowed to die due to the weakening or delay of these health safeguards. How many more pregnant women and children will be poisoned by mercury in their bodies if Congress delays or weakens health safeguards covering these industries? How many additional hundreds of thousands of cases of asthma attacks, heart attacks, and trips to the ER would be permitted to occur?

Before Congress even considers setting the country on this course, I urge you to convene legislative hearings not with lawyers, lobbyists, and corporate executives, but with doctors, nurses, and respiratory therapists. Please invite a panel with a pregnant mother-to-be, a religious leader, and a specialist in neurotoxins to discuss the impacts of delayed cleanup on the most vulnerable in our care, the more than 300,000 newborns each year in the U.S. that may have been overexposed to mercury in utero, increasing their risk of neural developmental effects.

These EPA rulemakings have been conducted pursuant to clear statutory authorities and court orders following court decisions that vacated and remanded earlier unlawful standards issued by the prior administration for these industries. Indeed, for critics that complain about the concentration of several standards by the current administration during its first 2 years, there is a very simple explanation. EPA, under the prior administration, violated the Clean Air Act repeatedly over two terms, courts sent those standards back to EPA for correction, the prior administration left office without fixing those standards, and now the current administration must fix the standards to follow the law.

We Americans deserve to have our government follow the law, to enforce the law. Americans have the right to clean air, a right conferred in the Clean Air Act of 1990 by a Republican President, 89 Senators, and 400 Members of this House. Congress should not take away our right to clean air.

In conclusion, there can be no claim that EPA lacks statutory authority to protect Americans against poison and cancer-causing chemicals. There can be no complaint that EPA is acting too quickly after well over a decade of delay, fueled by special interest and law-breaking. There should be no willingness to entertain delays of health protections that will avoid up to 26,000 deaths, nearly 180,000 asthma attacks, and mercury poisoning of society's most vulnerable. I respectfully ask you to let the clean air work to protect the health of all Americans.

Thank you.

[The prepared statement of Mr. Walke follows:]

Summary of Testimony by John Walke, Natural Resources Defense Council

Power plants, industrial boilers and process heaters, and cement plants are the largest emitters of mercury and scores of other toxic air pollution that still are failing to comply with basic Clean Air Act requirements for toxic pollution over two decades after the adoption of the 1990 amendments to this landmark statute. This situation is due to unlawful delays and standards by the prior administration that have resulted in the obligation by the present EPA to re-propose and re-issue lawful air toxics standards to protect the public.

EPA's final and proposed mercury and air toxics standards for these three industrial sectors will deliver enormous public health benefits. Were these standards to be delayed by even a single year, the potential magnitude of extreme health consequences would be as follows:

- 26,000 premature deaths;
- 16,500 non-fatal heart attacks;
- 178,000 asthma attacks;
- 12,000 cases of acute or chronic bronchitis;
- 330,000 cases of upper or lower respiratory symptoms;
- 18,000 hospital admissions and emergency room visits;
- 1,290,000 days when people must miss work or school; and
- 7,750,000 days when people must restrict their activities.

It would be irresponsible to deny these health benefits to the American people.

These EPA rulemakings have been conducted pursuant to clear statutory authorities and court orders, following *vacaturs* and remands of earlier, unlawful standards. These standards reflect EPA doing its job and not over-reaching. Congress has not changed – and should not change – the longstanding statutory authorities requiring EPA to protect Americans from mercury and other toxic air pollution.

TESTIMONY OF JOHN D. WALKE
CLEAN AIR DIRECTOR
NATURAL RESOURCES DEFENSE COUNCIL

HEARING ON "RECENT EPA RULEMAKINGS RELATING TO
BOILERS, CEMENT MANUFACTURING PLANTS, AND UTILITIES"
BEFORE THE SUBCOMMITTEE ON ENERGY AND POWER,
COMMITTEE ON ENERGY AND COMMERCE
U.S. HOUSE OF REPRESENTATIVES

April 15, 2011

Thank you, Chairman Whitfield and Ranking Member Rush, for the opportunity to testify today. My name is John Walke, and I am clean air director and senior attorney for the Natural Resources Defense Council (NRDC). NRDC is a nonprofit organization of scientists, lawyers, and environmental specialists dedicated to protecting public health and the environment. Founded in 1970, NRDC has more than 1.2 million members and online activists nationwide, served from offices in New York, Washington, Los Angeles, San Francisco, Chicago, and Beijing. I have worked at NRDC since 2000, and before that I was a Clean Air Act attorney in the Office of General Counsel for the U.S. Environmental Protection Agency. Over the last decade, I represented NRDC in many of the rulemakings and lawsuits concerning mercury and air toxics standards discussed in my testimony.

Mercury and Air Toxics Standards under the Clean Air Act

Today's hearing addresses final or proposed mercury and air toxics standards from the three largest sources of industrial mercury pollution in the United States – power plants, industrial boilers and process heaters, and cement plants. Collectively these plants are also the largest emitters of mercury and scores of other toxic air pollution that still are failing to comply with basic Clean Air Act requirements to reduce toxic pollution, over two decades after the adoption of the 1990 amendments to this landmark statute.

Since the 1990 amendments, over 100 air toxics standards have been adopted covering many hundreds of industrial source categories, including chemical plants, oil refineries, manufacturers, steel plants and others. But with respect to power plants, cement plants, and industrial boilers and process heaters, this period has yielded instead inexcusable delay and unlawful standards, all resulting in a failure to achieve legally required reductions in these facilities' toxic air pollution.

Now that EPA finally has adopted required mercury and air toxies standards, appeals are being made to delay, weaken or block these safeguards. These appeals are fundamentally irresponsible and should be rejected.

The final and proposed health safeguards for these three industrial categories will deliver the following enormous benefits to the American people every year.

Power plants: EPA's proposed mercury and air toxics standards for power plants that burn coal and oil are projected to save as many as 17,000 American lives every year by 2015.[1] These standards also will prevent up to 11,000 cases of heart attacks, 120,000 cases of asthma attacks, 11,000 cases of acute bronchitis among children, 12,000 emergency room and hospital visits and 850,000 lost work days every year.

The proposed standards are expected to reduce mercury emissions from power plants burning coal and oil by 91%, acid gas pollution by 91%, direct particulate matter (PM) emissions by 30% and sulfur dioxide (SO2) emissions by 53%, down to 2.1 million tons of annual SO_2 emissions.

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[1] See generally http://www.epa.gov/airquality/powerplanttoxics/pdfs/overviewfactsheet.pdf.

Due to these tremendous health benefits, the proposed standards are estimated to yield monetized benefits of $59 billion to $140 billion annually, compared to annual compliance costs of approximately $10.9 billion. This represents $5 to $13 in health benefits for every $1 spent to reduce pollution.

Cement plants: EPA's final mercury and air toxics standards for cement plants are estimated to save as many as 2,500 lives every year by 2013.[2] The standards also will prevent up to 17,000 cases of aggravated asthma, 1,500 heart attacks, 32,000 cases of upper and lower respiratory symptoms, and 130,000 days of lost work, annually by the year 2013.

The safeguards will reduce annual emissions of cement plants' mercury by 16,600 pounds (a 92% cut), acid gases by 5,800 tons (97% cut), soot pollution by 11,500 tons (92% cut) and sulfur dioxide pollution by 110,000 (78% cut).

These standards will produce benefits of $6.7 billion to $18 billion annually, yielding benefits that outweigh costs by a factor of 7 to 20:1.

Boilers and process heaters: EPA's final mercury and air toxics standards for industrial, commercial and institutional boilers and process heaters are estimated to save as many as 6,500 lives every year by 2014.[3] The safeguards also will prevent up to 41,000 cases of aggravated asthma, 4,000 heart attacks, 1,600 cases of chronic bronchitis, 3,700 cases of acute bronchitis, 4,300 hospital and emergency room visits, and 78,000 cases of respiratory symptoms, and 310,000 lost work or school days every year starting in 2014.

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[2] See generally http://www.epa.gov/ttn/atw/pcem/pcem_fs_080910.pdf.

[3] See generally http://www.epa.gov/airquality/combustion/docs/20110221mboilersfs.pdf.

The standards will reduce nationwide emissions from the covered entities by 2,800 pounds per year of mercury, 2,700 tons per year (tpy) of non-mercury metals, 30,000 tpy of HCl, 47,000 tpy of PM, 440,000 tpy of SO2, and 7,000 tpy of volatile organic compounds (which are hazardous and contribute to smog formation).

EPA estimates that the standards will provide benefits of $22 to 54 billion in 2014, compared to compliance costs of $1.4 billion per year, representing $18 to $39 in health benefits for every $1 spent to reduce pollution.

Delay Would Mean More Deaths and Disease

According to recent media reports, members of this Committee are planning legislation to weaken and/or delay one or more of the mercury and air toxics standards at issue in today's hearing. This would be deeply irresponsible. As discussed below, power plants, cement plants and boilers have escaped required reductions in mercury and dozens of other toxic air pollutants for a decade or longer, exposing Americans to dangerous and deadly air pollution.

Before we see the details of any weakening legislation, let me catalogue the potential magnitude of extreme health impacts caused by a single additional year of delay for these three sets of health standards:

- 26,000 premature deaths;
- 16,500 non-fatal heart attacks;
- 178,000 asthma attacks;
- 12,000 cases of acute or chronic bronchitis;
- 330,000 cases of upper or lower respiratory symptoms;

- 18,000 hospital admissions and emergency room visits;
- 1,290,000 days when people must miss work or school; and
- 7,750,000 days when people must restrict their activities.

I respectfully ask Members to be honest with Americans about how many people will be allowed to die due to the weakening, delay or demise of these health safeguards. How many more pregnant women, children and fetuses will be poisoned by mercury in their bodies, if Congress delays or eliminate health safeguards covering the three biggest industrial pollution sources of mercury in the country today -- power plants, industrial boilers and cement plants? How many additional hundreds of thousands of cases of asthma attacks, bronchitis, heart attacks and trips to the ER must occur?

Before Congress even considers setting the country on this destructive course, I urge you to convene legislative hearings not with lawyers, lobbyists and company executives – but with doctors, nurses and respiratory therapists. These are the dedicated professionals that devote their talents and energies to helping asthmatic children gasping for air, aiding babies whose brains have been poisoned by their mother's mercury ingestion, and saving the lives of our elderly loved ones that suffer air pollution-induced heart attacks and strokes.

The American people deserve to know how and why their right to clean air is being restricted, after that right was promised in the 1990 Clean Air Act Amendments by overwhelming bi-partisan majorities in the House and Senate. The law was signed by a Republican President (George H. W. Bush), approved by 89 Senators (including 38 Republicans, all but 6), and 401 House members (including 154 Republicans, all but 16). And the earlier Clean Air Acts of 1977 and 1970 enjoyed equally broad bi-partisan support.

It would be a tragedy for the nation were that bi-partisan support to crumble in order to accommodate demands by polluters to increase emissions of toxic air pollution that cause cancer, neurotoxicity, heart attacks, asthma and premature deaths.

Clean Air Act Background

> As EPA has explained about the regulation of toxic air pollution under the Clean Air Act: Before the 1990 Clean Air Act Amendments, EPA regulated air toxics one chemical at a time. This approach did not work well. Between 1970 and 1990, EPA established regulations for only seven pollutants. The 1990 Clean Air Act Amendments took a completely different approach to reducing toxic air pollutants. The Amendments required EPA to identify categories of industrial sources for 187 listed toxic air pollutants and to take steps to reduce pollution by requiring sources to install controls or change production processes. It makes good sense to regulate by categories of industries rather than one pollutant at a time, since many individual sources release more than one toxic chemical. Developing controls and process changes for industrial source categories can result in major reductions in releases of multiple pollutants at one time.

See generally http://www.epa.gov/air/caa/peg/toxics.html. In enacting the 1990 Clean Air Act, Congress "requires EPA to set regulations using a technology-based or performance-based approach to reduce toxic emissions from industrial sources." This approach is called the Maximum Achievable Control Technology (MACT) program and requires performance standards to be based upon the emissions reductions achieved by the cleanest facilities in an industrial sector, the average of the top 12% of lowest emitting plants or equipment. As the agency's guide explains, "[i]n most cases, EPA does not prescribe a specific control technology, but sets a performance level based on a technology or other practices already used by the better-controlled and lower emitting sources in an industry."

Since the 1990 update to the Clean Air Act, EPA has adopted over 120 toxic air pollutant standards under the Act, covering literally hundreds of different types of industrial operations and equipment categories.[4] These include chemical plants, oil refineries, hazardous waste incinerators, iron and steel foundries, battery manufacturers, pharmaceutical plants, lead smelters, semiconductor manufacturers and fiberglass plants, among many others.

In 1992 EPA published a list of industrial categories for which it would develop toxic air pollution standards under the law's new MACT program. Cement plants and industrial boilers were added to the list at that time. NRDC filed suit against EPA alleging that the agency unlawfully omitted power plants from that list.

The example of power plants. Power plants and their toxic air pollution deserve special attention because of the lengthy history of delay since the 1990 law, and the truly extreme and irresponsible actions by the prior administration that led us to where we are today.

Under the Clean Air Act, EPA was supposed to conduct a health effects study addressing whether the agency should regulate toxic air pollution from fossil fuel-fired power plants using MACT standards. The law requires such regulation if EPA determines that it is "appropriate and necessary." As a result of the original lawsuit, NRDC and EPA entered into a settlement agreement in 1994, under which EPA was required to complete the study and report to Congress by November 1995. Following several delays, EPA submitted the report to Congress in February

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[4] See generally http://www.epa.gov/ttn/atw/mactfnlalph.html.

1998 – but still without making a determination about the appropriateness and necessity of MACT standards.[5]

Following notice of intent to file an "unreasonable delay" lawsuit by NRDC and the Sierra Club later in 1998, the original NRDC settlement agreement was modified twice more to require EPA to make the necessary regulatory determination by December 15, 2000. Then-EPA Administrator Carol Browner did so and determined that it was "appropriate and necessary" to reduce toxic air pollutants from fossil fuel-fired power plants using the law's protective MACT standards.

Soon after taking office, signs emerged that the Bush administration would not follow the law and issue the MACT standards for power plants required by the Clean Air Act. In a now notorious April 2001 speech that was recorded and transcribed without his awareness, a utility industry lobbyist told his coal industry audience that EPA had been planning to use the agency's existing authority under the Clean Air Act to require large and prompt reductions in toxic air pollution from coal-burning power plants, namely MACT standards.[6] Never fear, the lobbyist assured his colleagues, he and his friends in the Bush White House had a plan: the Administration would create what the lobbyist called the "next generation of regulatory programs" for power plants. Predicting precisely what unfolded under the Bush administration, the lobbyist boasted that "the goal here will be to gain a foothold, an irreversible foothold on the next generation of reasonable cost effective SO_2 and NO_x reduction, plus air toxics that we can all live with and that someone else can't undo." Observing that "mercury is the killer," the lobbyist signaled that eliminating the obligation to comply with MACT standards to reduce mercury and toxic air pollutants would be the very highest priority for the utility industry.

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[5] See http://www.epa.gov/ttn/atw/combust/utiltox/eurtc1.pdf.

[6] See http://www.nrdc.org/media/docs/050202.pdf.

And the Bush administration obliged that desire fully, developing legislation that actually would have *repealed* the MACT program to prevent its application to power plants' toxic air pollution, ignoring over six dozen different toxic air pollutants from power plants (like arsenic, lead and dioxins) and substituting much weaker and delayed standards covering mercury alone. The eventual bill that was introduced before the Senate Environment and Public Works Committee, the "Clear Skies Act of 2005", S.131, failed to be reported out of Committee following an unsuccessful vote in March 2005.

Following the Senate Committee vote, the Bush Administration set out to implement the central features of its Clear Skies legislation through a series of EPA regulations under the current Clean Air Act. The most harmful feature of the failed legislation concerning toxic air pollution – the repeal of the Act's MACT standards – was carried out *administratively* by the Bush administration in the form of two rulemakings, despite the absence of any statutory authority whatsoever for these administrative actions.

These rulemakings were proposed in 2004 and made clear immediately that the Bush administration had no intention of following the law to require MACT standards that would reduce all toxic air pollutants from power plants. Then in early 2005, the administration confirmed that fear by purporting to retract EPA's prior commitment to protect public health by requiring MACT standards for toxic pollution from power plants, issuing a so-called "rescission rule". Simultaneously, EPA issued a mercury "cap-and-trade" rule that purported to require significant reductions in power plant mercury emissions but in fact delayed *any* mercury regulation for 13 years. That rule disclaimed any need to reduce the remaining 70 or so toxic air pollutants from power plants and left power plants' toxic air pollutants like arsenic, lead, dioxins, acid gases and heavy metals completely unregulated.

The two rules immediately were challenged by a coalition of state attorneys general from across the country, as well as public health and conservations groups, in a case called *New Jersey v. EPA.* In February 2008, the U.S. Court of Appeals for the D.C. Circuit ruled unanimously that EPA had illegally evaded the Clean Air Act's protective, required safeguards -- MACT standards -- that should have required deep and timely reductions in all toxic air pollution, including mercury, from the nation's coal-fired power plants.[7]

The Court further ruled that EPA had illegally substituted a mercury pollution trading scheme for the protections required by the Clean Air Act. The Court vacated the EPA rules and made clear that EPA now had a firm legal obligation to adopt MACT standards to reduce all toxic air pollutants from power plants.

The unanimous court ruling even went so far as to mock EPA's defiance of the plain language of the law. The Court compared EPA's actions to the capricious Queen of Hearts in "Alice in Wonderland," since EPA had – in the Court's words – "substituted [its] desires for the plain text" of the law. This ruling made clear that the violations were not mere legal technicalities, but instead were actions that defied the plain language of the Clean Air Act and skirted a necessary health demonstration that the Bush administration had not even attempted to make because it knew it could not.

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[7] See http://pacer.cadc.uscourts.gov/docs/common/opinions/200802/05-1097a.pdf.

The Court vacated both unlawful EPA rules in its February 2008 decision and remanded them to EPA for re-proposal and re-issuance under required Clean Air Act safeguards, the MACT standards.

Unlawful Standards and Illegal Delay Brought Us to Where We Are Today

Accordingly, when the current administration took office in early 2009, it inherited the obligation to correct and re-issue mercury and air toxics standards for power plants and several other industrial categories, following numerous court decisions that overturned unlawful and un-protective standard issued by the prior administration.[8] These standards already were long overdue when issued, but they were grossly overdue by the time the courts remanded the illegal standards to EPA for correction. Of the three rules under discussion today, this was the case for the mercury and air toxics standards for industrial boilers and power plants, which were declared unlawful by the United States Court of Appeals for the D.C. Circuit in 2007 and early 2008, respectively.[9] EPA agreed voluntarily to correct and re-issue the standards for cement plants, following a string of court losses by the prior administration that made clear the cement standards would be declared unlawful as well. The Bush administration did not correct any of these legally deficient rules, but left them for the incoming Obama administration to fix.

And that is why these standards are being re-proposed or adopted only now by the Obama administration, some 21 years after the 1990 Clean Air Act Amendments.

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[8] See, *e.g., Mossville v.EPA*, 370 F. 3d 1232 (D.C. Cir. 2004) (Polyvinyl Chloride MACT Rule); *Sierra Club v. EPA*, No. 05-1441 (Hazardous Waste Combustor MACT); *Sierra Club v. EPA*, 479 F.3d 875 (D.C. Cir. 2007) (Brick and Structural Clay Products and Clay Ceramics MACT rules); *NRDC et al. v. EPA*, 489 F.3d 1250 (D.C. Cir. 2007) (Boiler MACT and CISWI Definitions rule); *Sierra Club v. EPA*, No. 06-1066 (Standards of Performance for New Stationary Sources and Emission Guidelines for Existing Sources: Other Solid Waste Incineration Units); *NRDC v. EPA*, 489 F.3d 1364 (D.C. Cir. 2007) (MACT for Plywood and Composite Wood Products Facilities); *State of New Jersey et al. v. EPA*, No. 05-1097, (D.C. Cir. Feb. 8, 2008) (Section 112(n) Revision Rule and Clean Air Mercury Rule).

[9] See *NRDC v. EPA, supra* (overturning air toxics standards for industrial boilers and solid waste incinerators); *State of New Jersey v. EPA, supra* (overturning mercury standards for power plants).

The Clean Air Act Works and Enjoys Overwhelming Public Support

The Clean Air Act is one of our country's most successful public health and environmental laws in the past 40 years marking the modern environmental era. The EPA recently released a report on the health and economic health benefits of the 1990 Clean Air Act amendments, assessed from 1990 to 2020.[10] The agency found that the Clean Air Act has saved over 160,000 lives every year by the year 2010, and the law will save over 230,000 lives every year by the year 2020.

NRDC analyzed the EPA report beyond the two target years of 2010 and 2020 in order to arrive at a cumulative assessment of the lives saved by the 1990 Clean Air Act Amendments by the year 2020. As summarized by my colleague, Christina Angelides:

> NRDC's own analysis of EPA's report shows that the 1990 amendments will have cumulatively saved **4.2 million lives** and avoided millions of cases of pollution-related illness by 2020 — including **43.8 million cases of asthma exacerbation, 3.3 million heart attacks, 2.1 million hospital admissions and 2.2 million emergency room visits, and 313 million lost work days**. For comparative purposes, 4.2 million is about the population of the city of Los Angeles.

A more detailed break-down of the avoided healthy impacts is presented in the following table (the blue portion is from the EPA report, while the green reflects NRDC's additional analysis)[11]:

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[10] See generally http://www.epa.gov/air/sect812/prospective2.html.

[11] See generally http://switchboard.nrdc.org/blogs/cangelides/the_1990_clean_air_act_will_sa.html.

[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
PM 2.5 Adult Mortality	PM	[illegible]	[illegible]	[illegible]	[illegible]
PM 2.5 Infant Mortality	PM	[illegible]	[illegible]	[illegible]	[illegible]
Ozone Mortality	Ozone	[illegible]	[illegible]	[illegible]	[illegible]
Chronic Bronchitis	PM	[illegible]	[illegible]	[illegible]	[illegible]
Acute Bronchitis	PM	[illegible]	[illegible]	[illegible]	[illegible]
Non-Fatal Myocardial Infarction	PM	[illegible]	[illegible]	[illegible]	[illegible]
Asthma Exacerbation	PM	[illegible]	[illegible]	[illegible]	[illegible]
Hospital Admissions	PM, Ozone	[illegible]	[illegible]	[illegible]	[illegible]
Emergency Room Visits	PM, Ozone	[illegible]	[illegible]	[illegible]	[illegible]
Restricted Activity Days	PM, Ozone	[illegible]	[illegible]	[illegible]	[illegible]
Lost School Days	Ozone	[illegible]	[illegible]	[illegible]	[illegible]
Lost Work Days	PM	[illegible]	[illegible]	[illegible]	[illegible]

*Data from Table 5-6, Environmental Protection Agency, The Benefits and Costs of the Clean Air Act: 1990 to 2020, February 2011, p.5-25.

**To estimate the cumulative life savings and health benefits of the 1990 amendments from 1990 to 2020, NRDC assumed a roughly linear growth rate to interpolate benefit estimates for each year from 1995–when EPA's Acid Rain Program Phase I began to secure the first benefits under the amendments–through 2010, and benefit estimates for each year from 2010 to 2020. These annual benefit estimates were then aggregated across the entire period.

The Clean Air Act – and its toxic air pollution measures in particular – continue to enjoy tremendous support from the American people, as well as our nation's health and medical professionals. A nationwide poll conducted by Public Policy Polling and released by the NRDC reports how registered voters feel about U.S. House Members' actions to block public health safeguards.

- 66% of Americans – including 54% of Republicans and 61% of Independents – support "requiring stricter limits on the amount of toxic chemicals such as mercury, lead, and arsenic that coal power plants and other industrial facilities release."
- 64% favor "requiring stricter limits on the amount of smog that vehicles and industrial facilities release."

In a recent CNN poll conducted by the Opinion Research Corporation from April 9-10, 71% of adult Americans polled responded that the federal government should continue to provide funding to the EPA to enforce regulations on greenhouse gases and other environmental issues. This included 80% of respondents from the Midwest and 71% from the South.

I am attaching to my testimony letters from health professionals attesting to the need to fully implement and enforce the Clean Air Act to protect public health. In a February 9, 2011 letter, 1,882 physicians, nurses, respiratory therapists, certified asthma educators and other health and medical professionals from all 50 states and the District of Columbia urged members of Congress to "[s]upport full implementation of the Clean Air Act and resist any efforts to weaken, delay or block progress toward a healthier future for all Americans."

On February 15, 2011, health organizations ranging from the American Lung Association to the American College of Preventive Medicine wrote in strong opposition to H.J. Res. 9. This pending resolution under the Congressional Review Act would overturn the health standards limiting mercury and air toxic air pollution from cement plants. The groups wrote: "As the American Academy of Pediatrics notes, 'mercury in all of its forms is toxic to the fetus and children, and efforts should be made to reduce exposure to the extent possible to pregnant women and children as well as the general population.' Cement plants are the third-largest source of human-caused mercury emissions; rolling back mercury standards for such plants would be a step in exactly the wrong direction."

Finally, an April 4, 2011 letter from nearly 500 public health, medical, faith, consumer, community, conservation, and other groups urged Congress "to uphold the Clean Air Act and to reject any measure that would block or delay the U.S. Environmental Protection Agency from doing its job to protect all Americans from life-threatening air pollution." These organizations urged full Congressional support for EPA fulfilling its statutory responsibilities to reduce smog, soot and toxic air pollution – which is exactly what the power plant, boiler and cement mercury and air toxics standards will do.

These letters and polling data make clear that any efforts to weaken or delay these clean air safeguards will face strong public opposition, above all from the health and medical organizations and individuals who devote their lives to helping the public lead healthy lives.

Recent Congressional Attacks on Clean Air Safeguards Are Failing the Public

Today's hearing *follows* a vote in which a majority of the House approved an amendment to H.R. 1's budget bill to block implementation and enforcement of the mercury and air toxics standards for cement plants. That blocking vote occurred despite no legislative hearings, no expert witnesses, no factual record, and fewer than 40 minutes of debate by nine members of Congress.

Today's hearing rightly will be seen by the American people as an after-the-fact trial for clean air protections that already have been convicted by a majority of the House of Representatives. That's not putting the cart before the horse; that's killing the horse, then using a cart to haul away the carcass.

The American people deserve better. The cement vote on H.R.1 marked the first time in the forty-year history of the Clean Air Act that a majority of the House of Representatives had voted to block EPA from implementing and enforcing standards to sharply reduce mercury and other toxic air emissions from a polluting industry. That legislative rider was dropped from the final budget agreement last week following opposition from the Senate, White House and hundreds of health, medical and other organizations. See *supra.*

The American people deserve better than to see these political favors for polluting interests renewed and extended to multiple mercury and air toxics standards that save lives, stop mercury poisoning and protect the public.

The Myth of EPA as "Rogue" Agency

Some critics of EPA regulations – such as the mercury and air toxics standards for cement plants, boilers and power plants – have charged EPA with being a "rogue" agency. This overheated rhetorical indictment should be dismissed simply because it is leveled invariably when there is a disagreement over the agency's legal or policy decisions. But to examine the charge more fully, it's fair to say that it has been based upon two other claims that bear examination in the context of today's hearing: (1) that EPA is acting outside the scope of statutory authority conferred by Congress; and (2) that EPA is acting precipitously and the current administration is regulating at a much higher regulatory pace than prior administrations. Both of these claims are false.

First, EPA has acted within plain statutory authority in adopting final mercury and air toxics standards for cement plants and industrial boilers, and proposing such standards for power plants that burn coal and oil. Section 112 of the Clean Air Act confers clear authority to adopt such MACT standards for all hazardous air pollutants from listed stationary source categories, including the three identified industrial categories. Indeed, the EPA is following the instructions and legal precedents in a series of D.C. Circuit court decisions that overturned a string of Bush administration EPA rulemakings for violating the plain language of the Clean Air Act.

Industry attorneys have yet to identify any instances in which EPA's recent final or proposed mercury and air toxics standards are similarly violating the plain language of the Act. I invite Committee members to examine whether any of the other witnesses for today's hearing make such demonstrations of EPA unlawfulness in their testimony. But even if industry representatives believe the final or proposed standards to be unlawful in some respect, they have the same legal recourse as the state attorneys general and public health and conservation groups that successfully challenged a host of unlawful Bush EPA rules: (1) to file administrative comments criticizing EPA's proposed standards; and (2) to file lawsuits challenging final standards. If the industry challenges are meritorious, the courts will remand the standards to EPA for correction in order to deliver on the statutory promise of clean air to the public. If the industry challenges lack merit, the American people will enjoy the benefits of standards with enormous public health and environmental benefits.

EPA critics also have attacked the mercury and air toxics standards and similar health safeguards by arguing that the current administration is regulating at a much faster, heavier regulatory pace than prior administrations. For example, a November 22, 2010 editorial in the Wall Street Journal charged that the Obama EPA's regulatory output has outpaced the entire first term of the Clinton Administration implementing the just-enacted 1990 Clean Air Act Amendments. This charge and similar ones are demonstrably false.

EPA Administrator Lisa Jackson has already specifically refuted such charges in an October 14, 2010 letter to Congressmen Barton and Burgess:

> The pace of EPA's Clean Air Act regulatory work under this administration is actually not faster than the pace under either of the two previous administrations. In fact, EPA has finalized or proposed fewer Clean Air Act rules (87) over the past 21 months than in the first two years of either President George W. Bush's administration (146) or President Clinton's administration (115).

Indeed, as discussed above, even this slower regulatory pace under the current administration has been a function of re-proposing and re-issuing numerous air pollution standards by the prior administration that were found unlawful. Those earlier unlawful standards and illegal delays brought us to where we are today.

Responses to Cement Industry Claims About the Mercury and Air Toxics Standards

The Portland Cement Association (PCA) has claimed that EPA's standards to reduce mercury and other toxic air pollution from cement kilns will overly burden their cement companies with compliance costs, close down plants and force U.S. cement production overseas, and threaten industry jobs. In a March 2011 analysis of Clean Air Standards, PCA even goes so far as to assert that the standards' toxic air pollution reductions are of "questionable environmental value."[12]

But the facts tell a very different story—despite EPA's strong regulatory impact analysis and PCA's own projections of cement industry growth released *after* the final standards, the Association is grossly overestimating the cost and economic impact of cleaning up its act and ignoring significant health, environmental, and economic benefits that will result from the standards.

EPA estimates that the standards will produce benefits of $6.7 billion to $18 billion annually, yielding benefits that far outweigh costs by a factor of 7 to 20:1.[13] The cement industry has available and cost-effective technologies to reduce pollution from their kilns and resources do so. As the organization Earthjustice notes in a recent January 2011 report, much of the cement industry — up to 80% of it — is dominated by major multinational corporations that are foreign-owned and have available resources to pay for emissions controls. In fact, some of these companies make more profits in six months than what EPA's rule would cost the entire industry in a year and are already complying with similar emissions standards in other countries in Europe.[14] Only 4 of the 40 cement parent companies are smaller entities, and, among them, two of the companies would have compliance costs less than 1% of sales and the other two companies no more than 3% of sales.[15] In one of its many devices to overestimate the costs of compliance, PCA assumes in its analysis that investments in pollution control equipment must be paid up front, rather than annualized over expected equipment lifetime, which is 20 years for most devices.

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[12] PCA, "Impact of Existing and Proposed EPA Standards on the U.S. Cement Industry," via http://www.cement.org/newsroom/Media_1pgr.pdf, (accessed 4-12-2011), p.1
[13] EPA, "Fact Sheet: Final Amendments to National Air Toxic Emission Standards and New Source Performance Standards for Portland Cement Manufacturing," via http://www.epa.gov/ttn/atw/pcem/pcem_fs_080910.pdf, (accessed 4-12-2011), p.4.
[14] Earthjustice, "Dirty Air is Not the Key to Economic Growth," via http://earthjustice.org/sites/default/files/cementkilnmythvsfact.pdf, (accessed 4-12-2011), p. 2.

PCA also overestimates plant closures and impacts on domestic production capacity, resulting in production moving overseas and increased imports. In fact, PCA fails to include a basic incidence analysis of key factors — such as the price of imported versus domestic cements, demand response to any price increases in domestic cement — to support their assumptions. While EPA has identified up to 10 plants that could be idled under the standards until market conditions improve, rapid expansion reported by the industry in recent years, projections of future growth by PCA and company proposals to add new production lines show that the industry's capacity is strong and growing.[16] [17] PCA's own November 2010 forecast estimates that domestic production will increase by more than 25 percent by 2013, while imports will increase only gradually and remain below more recent averages.[18]

Contrary to PCA's extreme claims of job loss, EPA projects that employment impacts on the industry will be minimal, ranging from a potential loss of 600 to a gain of 1,300 jobs.[19] This does not include additional jobs that will be created from the production, distribution, installation, and maintenance of pollution control equipment.

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[15] EPA, "Regulatory Impact Analysis: Amendments to the National Emission Standards for Hazardous Air Pollutants and New Source Performance Standards (NSPS) for the Portland Cement Manufacturing Industry," via http://www.epa.gov/ttn/ecas/regdata/RIAs/portlandcementfinalria.pdf, (accessed 4-12-2011), p. 1-3.

[16] EPA, "Regulatory Impact Analysis," p. 1-2.

[17] Earthjustice, "Dirty Air is Not the Key to Economic Growth," p.3.

[18] Earthjustice, "Dirty Air is Not the Key to Economic Growth," p.1.

[19] EPA, "Regulatory Impact Analysis," p. 1-2. Any potential job losses obviously are very real and distressing to the individuals whose jobs could be lost, and neither EPA nor any party is seeking that outcome. That unwelcome potential outcome, however, must be compared to an outcome in which up to 25,000 premature deaths will be avoided over the next decade as a result of the mercury and air toxics standards for cement plants.

The cement industry is one of the biggest toxic air polluters in the industrial sector and, for many decades has failed to reduce mercury and toxic air pollution to levels long required by the Clean Air Act, allowing this industry to escape standards that many other industrial sectors have been required to meet and are meeting.

For many communities concerned about the pollution that cement plants put in our air and water, the EPA standards are the only backstop to ensure adequate protection of our public health and environment. For example, in North Carolina, Titan America has proposed to build one of the largest cement plants in the country in Castle Hayne, near Wilmington, NC. Local North Carolina residents are fighting the project as the plant would be one of the largest emitters of mercury in the county; emit other toxic pollutants, including particular matter, nitrogen dioxide and sulfur dioxide; and expose an estimated 8,500 students enrolled within 5 miles of Titan's property to pollutants that cause asthma and other respiratory illnesses.[20] Local residents are pushing for a comprehensive environmental review before an air permit is issued by the state, to account for all the facility's health and environmental impacts.[21] Should the plant move forward despite the community's public health concerns, EPA's mercury and air toxic standards for cement plants will ensure that some critical safeguards will be in place, capping mercury emissions at 60 pounds per year instead of more than 400 pounds per year.

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[20] Stop Titan, "Why Stop Titan America?" via http://stoptitan.com/the-fight/why-stop-titan.asp, (accessed 4-12-2011).

[21] Gareth McGrath, "Judge says Titan's air quality permit application can proceed," Star News, 1/4/2011, via http://www.starnewsonline.com/article/20110104/ARTICLES/110109931/1155?p=1&tc=pg, (accessed 4-12-2011).

Industry Economic Studies Concerning the Cement and Boiler Standards

Despite the clear and overwhelming public health, economic and environmental benefits of these standards, industry trade associations have predictably released a number of studies over the past six months projecting grossly exaggerated economic impacts and job losses as part of their effort to weaken and block these critical safeguards. These analyses, including the American Forest Paper Association's (AFPA) and the Council of Industrial Boiler Owners' (CIBO) studies on the air toxic standards for industrial, commercial, and institutional boilers, and the PCA study on the air toxics standards for cement plants, fail to meet fundamental standards of economic methodology and analysis.

There are basic tricks these studies use to inflate the impact of these standards. All three studies fail to conduct a basic incidence analysis that assesses key factors, such as consumer response to any increased prices and the percentage of costs that producers are able to pass on to consumers, to determine the real effect of the standards on output and employment in a consistent way. For example, in its study of the air toxic standards for industrial, institutional and commercial boilers, CIBO mistakenly assumed that output from the industrial sector would be reduced by an amount equal to the capital investment required for compliance; however, without a proper analysis to determine how consumers and companies would respond, there is no basis for this assumption.[22] As noted earlier in this testimony, PCA's study also fails to look at basic incident components, including the price of imported versus domestic cement and how the price of imports will affect economic behavior.

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[22] Laurie Johnson, "Congressional Research Service: CIBO boiler study used flawed economics," NRDC Switchboard, 2-16-2011, via http://switchboard.nrdc.org/blogs/ljohnson/congressional_research_service.html, (accessed 4-13-2011) ("Congressional Research Service").

All of the studies also jack up the cost of compliance by modeling exorbitant cost estimates for pollution control equipment and assuming that this equipment must be paid for up front, rather than annualized over the life of the equipment, which is 20 years for most devices. AFPA's study projects compliance costs for the pulp and paper sector almost double that of EPA's analysis.[23] Likewise CIBO's cost estimates for pollution controls were far higher than EPA's, resulting in a total capital cost more than twice what EPA projects (CIBO's estimate was $20.7 billion compared to EPA's $9.5 billion). The Congressional Research Service also notes that CIBO grossly exaggerated compliance costs.[24]

These studies also ignore job gains from the production, distribution, installation and maintenance of pollution control equipment. The U.S. environmental technology industry generated $282 billion in revenues and $40 billion in exports and supported 1.6 million American jobs in 2007.[25] Typically, environmental standards result in a net gain in jobs as result of this industry's work, as well as the labor-intensive nature of these jobs.[26]

In what is likely one of the most egregious oversights, the studies completely disregard the significant health and environmental benefits of the standards. None of the studies assess these benefits in their reports. As noted earlier in my testimony, PCA's analysis goes so far as to question the inherent environmental value of the standards, despite never examining or quantifying these benefits in their analysis.[27]

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[23] Laurie Johnson, "Pulp and paper industry's junk economic analysis of proposed EPA toxic emission standards for industrial boilers," NRDC Switchboard, 10-1-2010, via http://switchboard.nrdc.org/blogs/ljohnson/pulp_and_paper_industrys_junk.html, (accessed 4-13-2011).

[24] Laurie Johnson, "Congressional Research Service."

[25] Administrator Lisa P. Jackson, Remarks on the 40th Anniversary of the Clean Air Act, As Prepared, September 14, 2010, via http://yosemite.epa.gov/opa/admpress.nsf/12a744ff56dbff8585257590004750b6/7769a6b1f0a5bc9a8525779e005ade13!OpenDocument, (accessed 2/27/2011).

[26] Laurie Johnson, "Congressional Research Service."

NRDC asked three respected academic economics professors to evaluate and grade a few industry reports, including CIBO's and AFPA' studies, as if they had been submitted to the professors as assignments in their undergraduate courses. The reports did not pass muster, earning grades of "D/F" and "F" respectively. As Professor Charles D. Kolstad of the University of California, Santa Barbara noted of the AFPA study, "If I were grading this, I would give it an F. The economics are all wrong (lack of incidence analysis or acknowledgement of its importance; failure to draw on the relevant literature)." Professor Jason Shogren of the University of Wyoming had a similar perspective on the CIBO study—"Overall grade: Application—D (lack of a serious accounting of economic behavior—no attempt to account for the behavioral elasticities of demand, a high end cost estimation, one-to-one mapping of upgrade costs to demand reduction, not addressing impacts in non-sector gainers within the economy, no accounting for R&D and new technology innovations and entrepreneurship). Transparency—F (Weak discussion on the basic economic role of responsiveness and substitution possibilities, multiplier justification is unclear, abatement cost assumptions incomplete, unclear, and inadequately justified)."[28]

Health Overview: Power Plants, Boilers and Cement Plants

Fossil fuel power plants, boilers and cement plants all pose a major health hazard not only to the people living around them, but also regionally and across the nation, as the pollutants emitted by these facilities contaminate communities, waterways and ecosystems across the United States and beyond. These industrial facilities emit vast quantities of deadly particulate matter or soot, smog-forming pollutants, and hazardous air pollutants such as acid gases, heavy metals like mercury, chromium, and lead, dangerous aromatics like benzene, and dioxins — a veritable toxic brew.

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[27] PCA, "Impact of Existing and Proposed EPA Standards on the U.S. Cement Industry," via http://www.cement.org/newsroom/Media_1pgr.pdf, (accessed 4-12-2011), p.1

[28] Laurie Johnson, "Industry Reports Attacking Clean Air Rules Earn Poor Grades from Professorts," NRDC Switchboard, 10-28-2010, via http://switchboard.nrdc.org/blogs/ljohnson/industry_reports_attacking_cle.html, (accessed 4-13-2011).

Health impacts of mercury

Mercury is a highly neurotoxic contaminant that is pervasive throughout watersheds where it accumulates in fish, other wildlife, and ultimately in humans.[29] Mercury contamination of fish stocks is widespread in the United States, with nearly every state (48 out of 50) posting health advisories for mercury in fish.[30] A recent study of mercury levels in fish in streams across the United States found toxic methyl-mercury levels exceeding the level for human health concern at nearly 30% of the sites sampled.[31] For example, there are 1,039 advisories for mercury contamination in fish in Minnesota alone; 120 advisories for mercury contamination in Michigan waterways; 113 such advisories in Ohio; and 11 in Kentucky.[32]

Newly deposited mercury has been shown to be more bioavailable and more rapidly converted to methylmercury and represents a greater fraction of the methylmercury that is incorporated into food chains and ultimately fish.[33] Local sources have been implicated in elevated levels of mercury measured in ambient air,[34] precipitation,[35] soils,[36] and methylmercury levels in biota including fish.[37] Reductions in local mercury emissions levels have been tied to decreasing levels measured in the environment and biota.[38]

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[29] US EPA 2009. Human Exposure to Methylmercury. http://www.epa.gov/mercury/exposure.htm.

[30] USGS. 2009. Recent findings from the National Water-Quality Assessment (NAWQA) and Toxic Substances Hydrology Programs (as presented to the NAWQA National Liaison Committee, August 21, 2009). US EPA 2007. National Listing of Fish Advisories Technical Fact Sheet: 2005/06 National Listing Fact Sheet; EPA-823-F-07-003; July 2007.
US Department of Health and Human Services and Environmental Protection Agency. 2009. What You Need to Know About Mercury in Fish and Shellfish. Available at http://www.fda.gov/Food/FoodSafety/Product-SpecificInformation/Seafood/FoodbornePathogensContaminants/Methylmercury/ucm115662.htm.

[31] USGS. 2009. Mercury in Fish, Bed Sediment, and Water from Streams Across the United States, 1998-2005.

[32] http://water.epa.gov/scitech/swguidance/fishshellfish/fishadvisories/advisories_index.cfm.

Therefore, in order to achieve the National Academy of Sciences public health goal to reduce mercury concentration in fish,[39] current mercury emissions must be ratcheted down to decrease the amount of mercury cycling through aquatic systems and reduce contamination of fish and people. Coal-fired power plants, boilers and cement plants contribute to half of all the mercury air emissions in the United States.

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[33] USGS. 2009. Mercury in Fish, Bed Sediment, and Water from Streams Across the United States, 1998-2005. Hintelmann H, Harris R, Heyes A, Hurley JP, Kelly CA, Krabbenhoft DP, et al. Reactivity and mobility of ne and old mercury deposition in a boreal forest ecosystem during the first year of the METAALICUS study. Environ. Sci. Technol. 36(23):5034-40, 2002.

[34] Manolopoulos H, Snyder DC, Schauer JJ, Hill JS, Turner JT, Olson ML, et al. Sources of speciated atmospheric mercury at a residential neighborhood impacted by industrial sources. Environ. Sci. Technol. 41(16):5626-33, 2007.

[35] Dvonch JT, Graney JR, Keeler GJ, Stevens RK. Use of elemental tracers to source apportion mercury in south Florida precipitation. Environ. Sci. Technol. 33(24):4522-27, 1999.
White EM, Keeler GJ, Landis MS. Spatial variability of mercury wet deposition in eastern Ohio: summertime meteorological case study analysis of local source influences. Environ. Sci. Technol. 43(13):4946-53, 2009.

[36] Biester H, Müller G, Schöler HF. Estimating distribution and retention of mercury in three different soils contaminated by emissions from chlor-alkali plants: part I. Sci. of the Tot. Environ. 284:177-89, 2002.

[37] Evers DC, Han Y, Driscoll CT, Kamman NC, Goodale MW, Lambert KT, et al. Biological mercury hotspots in the northeastern United States and southwestern Canada. Biosci. 57(1):29-43, 2007.

[38] Frederick PC, Hylton B, Heath JA, Spalding MA. A historical records of mercury contamination in southern Florida (USA) as inferred from avian feather tissue. Environ. Toxicol. and Chem. 23(6):1474-78, 2004. Driscoll CT, Han Y, Chen CY, Evers DC, Lambert KF, Holsen TM, et al. Mercury contamination in forest and freshwater ecosystems in the northeastern United States. Biosci. 57(1):17-28, 2007. USGS. 2009. Mercury in Fish, Bed Sediment, and Water from Streams Across the United States, 1998-2005.

[39] National Research Council. 2000, Toxicological Effects of Methylmercury. National Academy Press. Washington DC.

A significant fraction of the U.S. population already has elevated levels of mercury in their bodies, with an estimated 8% of women having mercury levels considered unsafe.[40] Further, *more than 300,000 newborns each year in the U.S. may have been over exposed to mercury in utero increasing their risk of neuro-developmental effects.*[41] Asians, Pacific Islanders, and Native Americans are all more likely to have elevated blood mercury levels, as are women living in the Northeast and other coastal areas, or consuming a lot of fish.[42] Researchers have estimated that in the U.S. methyl mercury toxicity is associated with between 115 and 2,675 excess cases per year of a level of cognitive impairment that would be considered mental retardation.[43] The cost of caring for these children has been estimated at between $28 million and $3.3 billion, a cost the researchers point out is accrued annually until mercury emissions are reduced.[44]

Methyl-mercury readily crosses the placenta and the blood brain barrier and is known to be neurotoxic, especially to the developing brain.[45] Several very large studies have shown solid associations between intrauterine methylmercury exposure and impaired neurobehavioral performance.[46] Neurological effects in children can also occur from early life exposures to mercury at low doses resulting in diminished visual recognition memory (VRM)[47] and other neurological impairments such as decreased visual motor development and receptive vocabulary.[48] Postnatal mercury exposure is also associated with ADHD as well as impacts to motor functions and IQ.[49] Some neurobehavioral deficits related to mercury exposure may take many years to manifest.[50]

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[40] Schober SE, Sinks TH, Jones RL, Bolger PM, McDowell M, Osterloh J, et al. Blood mercury levels in US children and women of childbearing age, 1999-2000. JAMA. 289(13):1667-74, 2003.

[41] Mahaffey KR, Clickner RP, Bodurow CC. Blood organic mercury and dietary mercury intake: National Health and Nutrition Examination Survey, 1999 and 2000. Environ Health Perspect. 112(5):562-70, 2004.

[42] Hightower JM, O'Hare A, Hernandez GT. Blood mercury reporting in NHANES: identifying Asian, Pacific Islander, Native American, and multiracial groups. Environ Health Perspect. 114(2):173-5, 2006. Mahaffey KR, Clickner RP, Jeffries RA. Adult women's blood mercury concentrations vary regionally in the United States: association with patterns of fish consumption (NHANES 1999-2004). Environ. Health Perspect. 117(1):47-53, 2009.

[43] Trasande, Leonardo, Schecter, Clyde, Haynes, Karla A., and Landrigan Phillip. Mental Retardation and Prenatial Methylmercury Toxicity. 2006 Am Journal of Industrial Medicine. 49:153-158.

[44] Trasande, Leonardo, Schecter, Clyde, Haynes, Karla A., and Landrigan Phillip. 2006. Applying Cost Analyses to Drive Policy that Protects Children Mercury as a Case Study. Ann. N.Y. Acad.Sci. 1076:911-923.

[45] Myers GJ, Davidson PW. Prenatal mercury exposure and children: Neurologic, developmental, and behavioral research. Environ Health Perspect 106(Suppl 3): 841-847, 1998.

Recent research has revealed that elevated levels of mercury in adults can trigger neurological deficits impacting fine motor speed, dexterity, concentration, verbal learning, and memory.[51] Cardiovascular effects have also been reported in adults at environmentally-relevant exposure levels, indicating increased risks of myocardial infarction (e.g. heart attacks), increased blood pressure, and thickening of the carotid artery (a measurement of atherosclerosis) associated with elevated mercury levels.[52]

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[46] Grandjean P, White RF, Weihe P, Jorgensen PJ. Neurotoxic risk caused by stable and variable exposure to methylmercury from seafood. Ambul Pediatr. 3(1):18-23, 2003.
Debes F, Budtz-Jørgensen E, Weihe P, White RF, Grandjean P. Impact of prenatal methylmercury exposure on neurobehavioral function at age 14 years. Neurotoxicol Teratol. 28(5):536-47, 2006.

[47] Oken E, Wright RO, Kleinman KP, Bellinger D, Amarasiriwardena CJ, Hu H, Rich-Edwards JW, Gillman MW. Maternal fish consumption, hair mercury, and infant cognition in a U.S. Cohort. Environ Health Perspect. 113(10):1376-80, 2005.

[48] Oken E, Radesky JS, Wright RO, Bellinger DC, Amarasiriwardena CJ, Kleinman KP, Hu H, Gillman MW. Maternal fish intake during pregnancy, blood mercury levels, and child cognition at age 3 years in a US cohort. Am J Epidemiol.167(10):1171-81, 2008.
Davidson PW, Myers GJ, Weiss B. Mercury exposure and child development outcomes. Pediatrics. 113(4 Suppl):1023-9, 2004. Oken E, Bellinger DC. Fish consumption, methylmercury and child neurodevelopment. Curr Opin Pediatr. 20(2):178-83, 2008.

[49] Myers GJ, Thurston SW, Pearson AT, Davidson PW, Cox C, Shamlaye CF, Cernichiari E, Clarkson TW. Postnatal exposure to methyl mercury from fish consumption: a review and new data from the Seychelles Child Development Study. Neurotoxicol. 30(3):338-49, 2009.

[50] Yoshida M, Shimizu N, Suzuki M, Watanabe C, Satoh M, Mori K, Yasutake A. Emergence of delayed methylmercury toxicity after perinatal exposure in metallothionein-null and wild-type C57BL mice. Environ Health Perspect. 116(6):746-51, 2008.

[51] Yokoo EM, Valente JG, Grattan L, Schmidt SL, Platt I, Silbergeld EK. Low level methylmercury exposure affects neuropsychological function in adults. Environ Health. 2(1):8, 2003.

[52] Guallar E, Sanz-Gallardo MI, van't Veer P, Bode P, Aro A, Gomez-Aracena J, et al. Mercury, fish oils, and the risk of myocardial infarction. N Engl J Med. 347(22):1747-54, 2002.

Health impacts of other toxic heavy metals[53]

Clean up standards for power plants, boilers and cement plants not only would make substantial reductions in mercury pollution, but also reduce other toxic heavy metals, including antimony, arsenic, beryllium, cadmium, chromium, cobalt, lead, manganese, nickel and selenium. Due to the low volatility of these metals, the majority of emissions occur as particles. The public is exposed through direct inhalation of metal containing particles and soil contamination resulting from aerial deposition of metals.

Hexavalent chromium, for example, is a known human carcinogen, primarily affecting the lungs, but tumors in the stomach and intestinal tract have also been reported.[54] Exposure to hexavalent chromium is also associated with respiratory effects (*e.g.*, nasal and lung irritation, altered pulmonary function), gastrointestinal effects (*e.g.*, irritation, ulceration and non-neoplastic lesions of the stomach and small intestine), hematological effects (*e.g.*, microcytic, hypochromic anemia), and reproductive effects (*e.g.*, effects on male reproductive organs, including decreased sperm count and histopathological change to the epididymis). Bronchitis, decreases in pulmonary function, pneumonia, and other respiratory effects have been noted from chronic high dose exposure of hexavalent chromium in occupational settings. Hexavalent

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Salonen JT, Seppanen K, Nyyssonen K, Korpela H, Kauhanen J, Kantola M, et al. Intake of mercury from fish, lipid peroxidation, and the risk of myocardial infarction and coronary, cardiovascular, and any death in eastern Finnish men. Circulation 91(3):645-55, 1995.
Choi AL, Weihe P, Budtz-Jørgensen E, Jørgensen PJ, Salonen JT, Tuomainen TP, Murata K, Nielsen HP, Petersen MS, Askham J, Grandjean P. Methylmercury exposure and adverse cardiovascular effects in Faroese whaling men. Environ. Health Perspect. 117(3):367-72, 2009.
Jacob-Ferreira AL, Passos CJ, Jordão AA, Fillion M, Mergler D, Lemire M, Gerlach RF, Barbosa Jr F, Tanus-Santos JE. Mercury Exposure Increases Circulating Net Matrix Metalloproteinase (MMP)-2 and MMP-9 Activities. Basic Clin. Pharmacol. Toxicol. 1-8, 2009 [Epub ahead of print] PMID: 19594729.

[53] 70 Fed. Reg. 59402, 59406-08 (Oct. 12, 2005), Agency for toxic substances and Disease Registry, Public Health Statements, http://www.atsdr.cdc.gov/.

[54] US DHHS, ATSDR. 2008. Draft Toxicological Profile For Chromium.

chromium inhalation exposure may be associated with complications during pregnancy and childbirth.

Another notoriously toxic heavy metal, lead, exerts ''a broad array of deleterious effects on multiple organ systems via widely diverse mechanisms of action," including effects on heme biosynthesis and related functions; neurological development and function; reproduction and physical development; kidney function; cardiovascular function; and immune function.[55] In particular, lead is associated with neurological, hematological, and immune effects on children, and hematological, cardiovascular and renal effects on adults. Children are particularly sensitive to the effects of lead. Functional manifestations of lead neurotoxicity during childhood include sensory, motor, cognitive and behavioral impacts. Cognitive effects of special concern include decrements in IQ scores and academic achievement, as well as attention deficit problems. Children in poverty and black, non-Hispanic children face higher exposures to lead and are consequently more susceptible to lead's health impacts. Reproductive effects, such as decreased sperm count in men and spontaneous abortions in women, have been associated with lead exposure. There is also some evidence of lead carcinogenicity, primarily from animal studies, together with limited human evidence of suggestive associations. EPA has classified lead as a probable human carcinogen.

Health impacts of acid gases[56]

Hydrogen chloride (HCl) is irritating and corrosive to any tissue it contacts. Brief exposure to low levels causes throat irritation. Long-term exposure to low levels can cause respiratory problems, eye and skin irritation, and discoloration of the teeth. Exposure to higher levels can result in rapid breathing, narrowing of the bronchioles, blue coloring of the skin, severe burns of the eyes and skin, accumulation of fluid in the lungs, and even death. Some people may develop reactive airways dysfunction syndrome (RADS), a type of asthma caused by some irritating or corrosive substances. Children may be more vulnerable than adults to corrosive agents, such as HCl, because of their relatively narrower airways, relatively greater exposure due to greater breathing volume per pound of body weight and relatively longer potential exposure durations. Hydrogen fluoride or Hydrofluoric acid (HF) is a serious systemic poison that is highly corrosive; exposure to it can be fatal.

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[55] National Ambient Air Quality Standards for Lead, 73 Fed. Reg. 66964, 66975-76 (Nov. 12, 2008).

[56] Agency of Toxic Substances and Disease Registry, ToxFAQs, http://www.atsdr.cdc.gov/toxfaqs/TF.asp?id=759&tid=147, ATSDR, Medical Management Guidelines for Hydrogen Fluoride, ttp://www.atsdr.cdc.gov/MMG/MMG.asp?id=1142&tid=250

Health impacts of organic chemicals[57]

Organic compounds emitted by coal boilers include but are not limited to acetaldehyde, benzene, formaldehyde, dioxin and furan, polycyclic aromatic hydrocarbons (PAHs), toluene, and xylenes. Each of these organic compounds is associated with a range of potential health effects. Several of the health effects from short-term inhalation exposure to these pollutants are similar: they include irritation of the eyes, skin, and respiratory tract in humans; central nervous system effects (e.g., drowsiness, dizziness, headaches, depression, nausea, irregular heartbeat); reproductive and developmental effects; and, neurological effects. Exposure to benzene at extremely high concentrations may lead to respiratory paralysis, coma, or death. Long-term inhalation exposure in humans produces health effects that range from mild to serious. Mild symptoms may include nausea, headache, weakness, insomnia, intestinal pain, and burning eyes. Long-term exposure also has effects on the central nervous system, can be toxic to the immune system, and can produce disorders of the blood, lead to reproductive disorders in women (*e.g.*, increased risk of spontaneous abortion), and is associated with developmental effects, gastrointestinal irritation, liver injury, and muscular effects. In addition, some of the organic

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[57] ATSDR, Public Health Statements, http://www.atsdr.cdc.gov/.

HAPs are either known human carcinogens, such as benzene, or probable carcinogens, such as formaldehyde and dioxins.

Polycyclic aromatic hydrocarbons (PAHs) are known human mutagens, carcinogens, and/or developmental toxicants.[58] Infants and children are *especially* sensitive and susceptible to the hazards of PAHs. Greater lifetime cancer risks result from early exposure to carcinogens (*i.e.*, at a young age), and many carcinogens can have a long latency period. These substances are known to cross the placenta to harm the unborn fetus; in addition to contributing to fetal mortality they have been shown to increase the cancer risk, and produce tumors as well as birth defects in offspring.[59] There is also evidence that exposure of children to PAHs at ambient levels in polluted areas can adversely affect IQ.[60] Further evidence suggests that prenatal exposure to PAHs may be a risk factor for the early development of asthma-related symptoms and can adversely affect children's cognitive development, with implications for diminished school performance.[61] Thus the adverse health impacts of PAH exposure to infants and children are significantly greater.

Health impacts of particulate matter.

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[58] Salmon A.G. and Meehan T. Potential Impact of Environmental Exposures to Polycyclic Organic Material (POM) on Children's Health, California Office of Environmental Health Hazard Assessment (OEHHA).
http://www.oehha.ca.gov/public_info/public/kids/pdf/PAHs%20on%20Children's%20Health.pdf
Agency for Toxic Substances and Disease Registry, Public Health Statement for Polycyclic Aromatic Hydrocarbons (PAHs). August 1995. http://www.atsdr.cdc.gov/PHS/PHS.asp?id=120&tid=25

[59] Perera FP. DNA Damage from Polycyclic Aromatic Hydrocarbons Measured by Benzo[a]pyrene-DNA Adducts in Mothers and Newborns from Northern Manhattan, The World Trade Center Area, Poland, and China, Cancer Epidemiol Biomarkers Prev 2005;14(3):709–14.

[60] Perera, FP et. al. Prenatal Airborne Polycyclic Aromatic Hydrocarbon Exposure and Child IQ at Age 5 Years. Pediatrics 2009;124:e195–e202.

[61] Perera FP, Rauh V, Tsai WY, Kinney P, Camann D, et al. (2003) Effects of transplacental exposure to environmental pollutants on birth outcomes in amultiethnic population. Environ Health Perspect 111: 201–205. Perera FP et. al., Effect of Prenatal Exposure to Airborne Polycyclic Aromatic Hydrocarbons on Neurodevelopment in the First 3 Years of Life among Inner-City Children, Environ Health Perspect 114:1287–1292 (2006).

In addition to the toxic constituents and associated health impacts above, these sources constitute a major public health hazard through fine particulate matter (PM) emissions. Numerous studies have documented a wide range of adverse health impacts from exposure to fine particulate matter, including increased risk for cardiovascular disease such as atherosclerosis, increased heart attacks, increased respiratory illness, increased emergency room visits for acute health events, birth defects, low birth weights, premature births, and increased rates of death.[62]

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[62] Kuenzli N, Jerrett M, Mack WJ, Beckerman B, LaBree L, Gilliland F, Thomas D, Hodis HN. "Ambient Air Pollution and Atherosclerosis in Los Angeles," Environ Health Perspect, 2005 Feb:113(2):201-6. Miller KA, Siscovick DS, Sheppard L, Shepherd K, Sullivan JH, Anderson GL, Kaufman JD. "Long-term Exposure to Air Pollution and Incidence of Cardiovascular Events in Women." N Engl J Med, 2007 Feb 1:356(5):447-58. Hoffman B, Moebus S, Mohlenkamp S, Stang A, Lehman N, Dragano D, Schmermund A, Memmesheimer M, Mann K, Erbel R, Jockel K-H. "Residential Exposure to Traffic Is Associated With Coronary Atherosclerosis." Circulation, published online July 16, 2007, DOI:10.1161 / CIRCULATIONAHA.107693622.
Pope CA, Muhlestein JB, May HT, Renlund DG, Anderson JL, Horne BD. "Ischemic Heart Disease Events Triggered by Short-term Exposure to Fine Particulate Air Pollution." Circulation 2006 Dec 5;114(23):2443-8. Schwartz J, Slater D, Larson TV, Person WE, Koenig JQ. "Particulate Air Pollution and Hospital Emergency Room Visits for Asthma in Seattle." Am Rev Respir Dis, 1993 Apr; 147(4):826-31. Ritz B, Wilhelm M, Zhao Y. "Air Pollution and Infant Death in Southern California, 1989–2000." Pediatrics, 2000 Aug:118(2):493-502. Wilhelm M, Ritz B. "Residential Proximity to Traffic and Adverse Birth Outcomes in Los Angeles County, California, 1994–1996." Environ Health Perspect, 2003 Feb; 111(2):207-16. Wilhelm M, Ritz B. "Local Variations in CO and Particulate Air Pollution and Adverse Birth outcomes in Los Angeles County, California, USA." Environ Health Perspect, 2005 Sep:113(9):1212-21.
Jerrett M, Burnett RT, Ma R, Pope CA, Krewski D, Newbold KB, Thurston G, Shi Y, Finkelstein N, Calle EE, Thun MJ. "Spatial Analysis of Air Pollution and Mortality in Los Angeles." Epidemiology, 2005 Nov:16(6):727-36.

February 9, 2011

U.S. House of Representatives
Washington, DC 20515

Dear Representative:

As health and medical professionals, we are keenly aware of the health impacts of air pollution. Air pollution is linked to a wide range of health consequences including cancer, asthma attacks, heart attacks and strokes. The Clean Air Act guarantees all Americans, especially the most vulnerable, air that is safe and healthy to breathe. Despite tremendous air pollution reductions, more progress is needed to fulfill this promise. Please support the full implementation and enforcement of the Clean Air Act.

Throughout its four decade history protecting the public from air pollution, the Clean Air Act has enjoyed strong bi-partisan support. The original Clean Air Act and its subsequent amendments received overwhelming votes in Congress. This landmark public health law directed the Environmental Protection Agency to protect health and the environment from air pollution. The result is saved lives and improved quality of life for millions of Americans. But the job is not finished. Communities across the nation still suffer from poor air quality. Low income families face the impacts of toxic air pollution every day. From smog causing asthma attacks to toxic mercury harming children's neurological development, far too many people face a constant threat from the air they breathe and the impacts of climate change.

Please fulfill the promise of clean, healthy air for all Americans to breathe. Support full implementation of the Clean Air Act and resist any efforts to weaken, delay or block progress toward a healthier future for all Americans.

Sincerely,

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Tonya Wheat, RHD
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Emily Green, DrPH
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Bountiful
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Cris G Cowley, MD
Cottonwood Heights
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Holladay
Douglas H Jones, MD
Layton
Jennifer Gilsoul, MD
Layton
Edward Redd, MD
Logan
Christine Nefcy, MD
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Donna M. Barhorst, MD
Ogden
Sam Rushforth, PhD
Orem
Shad Outsen, MD
Orem
Kathy Ostler, MD
Park City
Ernest A Bailey, MD
Provo
Polly Sheffield, MD, MPH
Provo
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Salt Lake City
Hannah L Kirking, MD
Salt Lake City
Holly Molberg, MD
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Kent Udell, PhD
Salt Lake City
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Salt Lake City
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Steven M. Lynch, MD
Salt Lake City
Sylvie Backman, MD, PhD
Salt Lake City
Theodore G Liou, MD
Salt Lake City
Virginia Vierra, MD
Salt Lake City
Yvonne Contreras, MD
Salt Lake City
Yvonne Hsu, MD
Salt Lake City
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Sandy
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St. George
David Tomer, MS, CCRP
West Valley City

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Brattleboro
Rebecca Jones, MD
Brattleboro
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Brownsville
Anne Dixon, MD
Burlington
Benjamin T. Suratt, MD
Burlingtan
Renee D. Stapleton, MD, PhD
Burlington
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Burlington
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Burlington
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Charlotte
Robert Mann, RN
Colchester
Jaanna Weinstock, MD
Jericho
Sally Cargill, MD
Montpelier
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Morrisville
Robert Primeau, MD
Newport
Richard White, MD
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Rutland
Mary Anne Riley, RRT, TTS
Springfield
Kyle Proctor, AHT
St. Albans
Richard A. Valentinetti, MPH
Waterbury
Amy M. Brewer, MPH
Williston

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Arlington
M. Suson Anderson, MPH
Ashburn
Lowell Smith, PhD
Berryville
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Luther Bartelt, MD
Charlottesville
Ed Malbach, PhD
Fairfox
Jane Harrison, MSW
Falls Church
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Franktown
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Glen Allen, Virginia
Charles Strickler, DDS
Harrisonburg
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Henrico
Lucie Ferguson, PhD
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Manassas
Linda Pereira, MA, COT
McLean
William Mccormick, VMD
Middleburg
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Norfolk
Katarzyna Kubzdela, PhD
Oakton
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Reston
Joseph Borzelleco, MD, MPH
Richmond
Thomas Williams, RRT, AS
Richmond
Anne Fairbanks, MSW
Roanoke
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Salem
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Stafford
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Suffolk
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Vienna
Janet Azar, PhD, RN
Virginia Beach
Joanie Haury, RN
White Marsh
Bruce Combs, PhD
Williamsbug
Christine Llewellyn, MD
Williamsbug
Glenn Shean, PhD
Williamsbug
Robert Leek, MHA
Williamsburg
Sandy Thompson, MSN
Woodbridge

Washington
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Bainbridge Island
Patricia Dawson, MD, PhD
Bainbridge Island
Elizabeth Allen, RN
Bellingham
Jeffrey Garrison, MD
Bellingham
Thomas Hall, MD
Bellingham
Wendy Courtemanche, BSN
Bellingham
Gene Nash, AAS, EMT
Bremerton
Richard Renner, MD
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Steve Kohl, MD, MSW
Brush Prairie
Patricia A Burke, PA-C
Burien
Kristin Adams, MD
Burton
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Cathlamet
Catherine Bray, MD
Chelan
Kathy J. Roberts, BSN, RN
Cheney
Virginia Hadley, RN, BS Ntrn, RH-AHG, CDP, CC
Cosmapolis
Gary Goldbaum, MD, MPH
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Howard Lazzarini, BA, RRT
Everett
Joseph Aharchi, PhD
Everett
Ann Johnson, BSN
Gig Harbor
J. David Heywood, MD
Kirkland
Stephanie Develle, MD
Kirkland
Tracy Hendershott, BS, PT
Kirkland
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Lacey
William Grady, MD
Lake Forest
Robert Stagman, MD
Mercer Island
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Port Townsed
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Sam Magnotto, BSN
Seattle
Steven Gilbert, PhD
Seattle
Susan Doederlein, MD
Seattle
Whitney Harrington, PhD
Seattle
William Silva, MD
Seattle
Darlene Schanfald, PhD
Sequim
Richard Rust, MD
Shoreline
William Green, MD
Shoreline
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Stanwood
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Patricia D. Moil, PhD, MPH
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Vancouver
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Wenatchee

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Martinsburg
David Fant, MHA
Martinsburg
Diana Gaviria, MD, MPH
Martinsburg
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Ravenswood
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La Crosse
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La Crosse
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Neenah
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Neenah
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Onalaska
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Onalaska
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Oshkosh
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Poynette
Andrew Rogahn, ADN
Poynette
Dorothy Campbell, RN
paynette
Tim D. Ballweg, RT
Prairie du Sac
Jenna Green, AAS
Rice Lake
Sheryl Scott, MPH
Richland Center
Peter Sigmann, MD
Sturgeon Bay
Kathleen Crittenden, PhD
Viroqua
David Knutzen, MD
Waunakee
Connie Metz, RN
Wausau
Holly Smith, MA
Wausau
Sally Roepe, RN, BSN
Wauwatosa
Mary Koller, RN, BSN
West Allis
Susan Sawyer Evans, RRT, BA
West Salem
Barbara Barczak, RN, BSN
Whitehall

Wyoming

Alex Bowler, MPH
Cheyenne
Joseph Grandpre, PhD, MPH
Cheyenne

An Open Letter to Congress from Groups Protecting Public Health

April 4, 2011

Dear Senator/Representative:

Representing public health and medical professionals and other clean air advocates, we stand united in calling on you to uphold the Clean Air Act and to reject any measure that would block or delay the U.S. Environmental Protection Agency from doing its job to protect all Americans from life-threatening air pollution.

Forty years ago, Congressional leaders from both parties wrote and passed the Clean Air Act. This law directed the Environmental Protection Agency (EPA) to protect public health and the environment. Since then this wise congressional legacy has saved lives and improved the quality of life for millions of Americans.

But the job is not yet done. Far too many of our communities still suffer from poor air quality. Too many families, particularly those of lower income, face the impacts of toxic air pollution every day. And far too many of our nation's children, elderly, and people with asthma, cardiovascular and lung diseases and diabetes live under added threats to their health from breathing polluted air and the impacts of global warming.

Over the coming years the EPA will be fulfilling its duty to reduce the smog and soot pollution, air toxics, and global warming pollution that are the cause of these public health threats. We urge you to fully support the EPA in fulfilling this responsibility. Doing so is quite literally a matter of life and death for tens of thousands of people and will mean the difference between chronic debilitating illness or a healthy life for hundreds of thousands more.

Once again, we urge you to support moving forward with protective clean air standards and to oppose any measure that would delay or block progress toward a healthier tomorrow for all Americans.

Sincerely,

Alabama
Alabama Chapter of the American Thoracic Society (ATS)
American Lung Association in Alabama
Cahaba Riverkeeper
Conservation Alabama
Group Against Smog and Pollution
The Shalom Center
Union for Reform Judaism

Alaska
Alaska Community Action on Toxics
American Lung Association in Alaska

Arizona
American Lung Association in Arizona
Arizona Asthma Coalition
Environment Arizona

Arkansas
American Lung Association in Arkansas

California
350.org
American Lung Association in California
Breathe California
California Academy of Family Physicians
California League of Conservation Voters
California Public Health Association-North
Catholic Charities, Diocese of Stockton
Catholic Healthcare West
Center for Biological Diversity
Citizen's Coalition for a Safe Community
Coalition for Clean Air
East Yard Communities for Environmental Justice
EcoEquity
Energy Independence Now
Environment California
Environmental Law Foundation
Families for Clean Air
Global Community Monitor
Global Green USA
Healthy Child Healthy World
Interfaith Power and Light
KyotoUSA
Napa County Asthma Coalition
Pacific Environment
Physicians for Social Responsibility, SF-Bay Area Chapter
Planning and Conservation League
Prevention Institute
Public Health Institute
Rainforest Action Network
Regional Asthma Management and Prevention
Rose Foundation for Communities & the Environment
San Diego Regional Asthma Coalition
Sierra Club
Siskiyou County Public Health Dept.
The Center for Energy Efficiency and Renewable Technologies
TURN-The Utility Reform Network
Voces Verdes

Colorado
Advanced Asthma Allergy and Immunology
American Lung Association in Colorado
Colorado Conservation Voters
Colorado Environmental Coalition
National Environmental Health Association
Western Organization of Resource Councils
Wilderness Workshop

Connecticut
American Lung Association in Connecticut
Citizens Campaign for the Environment
Coalition for a Safe and Healthy Connecticut
Connecticut Nurses' Association
Conservation Law Foundation
CT Coalition for Environmental Justice
Enviro Energy Connections
Environment Connecticut
The Great Land Conservation Trust

Delaware
American Lung Association in Delaware
Delaware Ecumenical Council on Children and Families
IMPACT Delaware Tobacco Prevention Coalition
Learning Express Academy
Learning Express Pre-school

District of Columbia
Alliance for Climate Protection
American Academy of Family Physicians
American Academy of Pediatrics
American College of Occupational and Environmental Medicine
American College of Preventive Medicine
American Heart Association
American Lung Association
American Lung Association in the District of Columbia
American Public Health Association
American Rivers
American Thoracic Society
Breakthrough Technologies Institute, Inc.
Chesapeake Climate Action Network
Children's Environmental Health Network
Clean Air Watch
Clean Water Action
Climate Protection Action Fund
Community Action Partnership
Consumers Union
Defenders of Wildlife
Earth Day Network
Earthjustice
Energy Action Coalition

Environment America
Environmental and Energy Study Institute
Environmental Defense Fund
Environmental Integrity Project
Friends Committee on National Legislation
Friends of the Earth
GREEN DMV
Green For All
Greenpeace USA
Jewish Council for Public Affairs
Labor Council for Latin American Advancement (LCLAA)
League of Conservation Voters
League of Women Voters of the United States
Metropolitan DC Thoracic Society
National Assembly on School-Based Health Care
National Association of County and City Health Officials
National Association of Local Boards of Health
National Audubon Society
National Consumer Law Center, on behalf of its low-income clients
National Consumers League
National Latino Coalition on Climate Change (NLCCC)
National Parks Conservation Association
National Physicians Alliance
National Wildlife Federation
Oil Change International
Pew Environment Group
Physicians for Social Responsibility
Public Citizen
Safe Climate Campaign
Solar Energy Industries Association
Southern Environmental Law Center
The Wilderness Society
Trust for America's Health
Union of Concerned Scientists
US Climate Action Network
Voices for Progress
World Wildlife Fund

Florida
American Lung Association in Florida
Common Ground for Conservation
Environment Florida
Farmworker Association of Florida
Florida Academy of Family Physicians
Florida Conservation Alliance
Southern Alliance for Clean Energy

Georgia
American Lung Association in Georgia
Morehouse School of Medicine
Mothers & Others for Clean Air
Southern Alliance for Clean Energy

Hawaii
American Lung Association in Hawaii
Conservation Council for Hawai'i
Hawaii Thoracic Society
Preserve Pepeekeo Health & Environment

Idaho
Climate Solutions
American Lung Association in Idaho

Illinois
American Association of Cardiovascular and Pulmonary Rehabilitation and National Home Oxygen Patients Association
American Bottom Conservancy
American College of Chest Physicians
American Lung Association in Illinois
Center for Neighborhood Technology
Chicago Clean Energy Alliance
Citizens Against Ruining the Environment
Eco-Justice Collaborative
Environment Illinois
Environmental Law & Policy Center
Foundation for Sarcoidosis Research
Protestants for the Common Good
Respiratory Health Association of Metropolitan Chicago

Indiana
American Lung Association in Indiana
Environmental Law & Policy Center
Valley Watch, Inc.

Iowa
American Lung Association in Iowa
Environment Iowa
Environmental Law & Policy Center

Kansas
American Lung Association in Kansas
Great Plains Alliance for Clean Energy
Kansas Public Health Association
Wichita Initiative to Renew the Environment [WIRE]

Kentucky
American Lung Association in Kentucky

Louisiana
American Lung Association in Louisiana
Louisiana Bucket Brigade

Maine
American Lung Association in Maine
Conservation Law Foundation
ENE (Environment Northeast)
Environment Maine
Frannie Peabody Center
Green Alliance
GrowSmart Maine
Lamey-Wellehan Shoes
Maine Council of Churches
Maine Migrant Health Program
Maine Osteopathic Association
Maine People's Alliance
Natural Resources Council of Maine
Portland Public Health Division
The Maine League of Young Voters

Toxics Action Center
Violence No More Inc.

Maryland
1Sky
American Lung Association in Maryland
Asthma and Allergy Foundation of America
Chesapeake Climate Action Network
Environment Maryland
Maryland League of Conservation Voters
Pulmonary Hypertension Association

Massachusetts
Global Warming Education Network
American Lung Association in Massachusetts
Ceres
Clean Air Task Force
Conservation Law Foundation
Environment Massachusetts
Environmental League of Massachusetts
Massachusetts Climate Action Network
Toxics Action Center Campaigns

Michigan
American Lung Association of Michigan
Ecology Center
Environment Michigan
Environmental Law & Policy Center
Great Lakes Environmental Law Center
Michigan Chapter of the Sierra Club
Michigan League of Conservation Voters Education Fund
Michigan Thoracic Society
West Michigan Environmental Action Council

Minnesota
Alliance for Sustainability
American Lung Association in Minnesota
Audubon Chapter of Minneapolis
Clean Up the River Environment (CURE)
Duluth Audubon Society
Environment Minnesota
Environmental Law & Policy Center
Fresh Energy
Helen Harris, Assistant Professor at
Minnesota University Moorhead School
of Nursing; RN, MS
Institute for Energy and Environmental Research
Institute for Local Self-Reliance
Izaak Walton League of America - Minnesota Division
League of Women Voters - Minnesota
League of Women Voters - Red River Valley Chapter
Mankato Area Environmentalists
Minnesota Center for Environmental Advocacy
Minnesota Conservation Federation
Minnesota Ornithologists' Union
Minnesota Renewable Energy Society
Minnesota State University Student Wildlife Society
Neighbors Against the Burner
Renewing the Countryside
Sierra Club North Star Chapter
Sierra Club, Red River Valley Chapter
Sierra Club, Red River Valley Chapter
St. Paul Audubon Society Chapter
Student Environmental Alliance - Concordia College
Take Back the Air
Transit for Livable Communities
Vicki Teske, MS, GNP, BC
Will Steger Foundation
Windustry
Women's Environmental Institute
Zimmer Environmental Improvement LLC

Mississippi
American Lung Association in Mississippi

Missouri
American Lung Association in Missouri
Concerned Citizens of Perryville
Environment Missouri
Missouri Votes Conservation
StraightUp Solar

Montana
American Lung Association in Montana
Climate Solutions
Environment Montana
Montana Audubon
Montana Environmental Information Center
Montana Nurses Association
Plains Justice
RiverStone Health
Western Organization of Resource Councils

Nebraska
American Lung Association in Nebraska

Nevada
American Lung Association in Nevada
Environment Nevada
Nevada Conservation League
Nevada Public Health Association
Nevada State Medical Association
Pulmonary Medicine Associates
Pulmonary Medicine Associates, Reno Nevada

New Hampshire
American Lung Association in New Hampshire
Children's Alliance of New Hampshire
Conservation Law Foundation
Green Alliance
Greenovations
New Hampshire Audubon
New Hampshire Pediatric Society
Revolution Energy, LLC
Toxics Action Center

New Jersey
American Lung Association in New Jersey
Center for the Sublime Arts
Environment New Jersey
National Center for Bicycling & Walking
New Jersey Thoracic Society
NJ/NY Environmental Watch

New Mexico
American Lung Association in New Mexico
Environment New Mexico
WildEarth Guardians

New York
Adirondack Mountain Club
American Lung Association in New York
Citizens Campaign for the Environment
Citizens' Environmental Coalition
Clean Air Coalition of Western New York
Clean New York
Coalition on the Environment and Jewish Life (COEJL)
Education for Global Warming Solutions
Environmental Advocates of New York
Federated Conservationists of Westchester County
Grassroots Environmental Education
Hudson River Sloop Clearwater, Inc.
Natural Resources Defense Council, (NRDC)
New York Interfaith Power & Light
New York League of Conservation Voters
New York Public Interest Research Group (NYPIRG)
New York Thoracic Society
NYC Environmental Justice Alliance
Pace Energy and Climate Center
Renewable Energy Long Island
West Harlem Environmental Action
Women's Environment and Development Organization

North Carolina
American Lung Association in North Carolina
Blue Ridge Environmental Defense League
Catawba Riverkeeper Foundation
Charlotte Energy Solutions
Clean Air Carolina
Cleveland County Asthma Coalition
Health Occupations Students of America
Mecklenburg County Medical Society
Media Savvy Marketing, Inc
NC Conservation Network
NC League of Conservation Voters
NC Waste Awareness & Reduction Network
North Carolina Interfaith Power and Light
North Carolina Pediatric Society
Pitt County Memorial Hospital
Southern Alliance for Clean Energy
The Canary Coalition
Western North Carolina Alliance

North Dakota
American Lung Association in North Dakota
Dakota Resource Council
Dakota Resource Council Clean Energy Task Force
Environmental Law & Policy Center
Grand Forks County Citizen Coalition
Institute for Complementary & Alternative Medicine
Sisters of the Presentation, Fargo
South Agassiz Resource Council
Western Organization of Resource Councils

Ohio
All Aboard Ohio
American Lung Association in Ohio
Buckeye Forest Council
Earth Day Coalition
Environment Ohio
Environmental Law & Policy Center
GreenCityBlueLake Institute
Heights Community Congress
New Agrarian Center
Ohio Asthma Coalition
Ohio Environmental Council
Ohio Society for Respiratory Care

Oklahoma
American Lung Association in Oklahoma

Oregon
American Lung Association in Oregon
Climate Solutions
Environment Oregon
Oregon Physicians for Social Responsibility
Oregon Environmental Council
Oregon Interfaith Power and Light
Oregon Thoracic Society
The Resource Innovation Group
Western Organization of Resource Councils

Pennsylvania
Allergy and Immunology Interest Group at Penn State College of Medicine
Allergy Section Penn State University
American Lung Association in Pennsylvania
Center for Creative Activities
Citizens for Pennsylvania's Future (PennFuture)
Clean Air Council
Conservation Consultants, Inc.
Conservation Voters of Pennsylvania
Democracia Inc.
DRMIII Ride For Asthma
Earthright
Edifice Rx
Energy Opportunites, Inc.
Family Health Council of Central PA, Inc.
Fourth Economy Consulting
Gettysburg Hospital- WellSpan Health
Group Against Smog & Pollution
Healthy Adams County Tobacco Prevention Task Force
Healthy Communities Partnership of Greater Franklin County
HMJ PATCH Program
iGrok, Inc.
Northern Dauphin County Branch YMCA
PA Association of School Nurses and Practitioners
PA Chapter, American Academy of Pediatrics
PA Public Health Association
PennEnvironment
Pennsylvania Coalition of Nurse Practitioners
Pennsylvania Society for Respiratory Care
Pennsylvania State Nurses Association
Pennsylvania Thoracic Society

Philadelphia Physicians for Social Responsibility
Physicians for Social Responsibility - Pittsburgh
Practical Energy Solutions
PrePEAR
Public Interest Law Center of Philadelphia
Pulmonary Associates, PC
Reed Group
Sierra Club, SE PA Group
Sisters of Mercy, Mid-Atlantic Justice Office
Students for Environmental Action
Sustainable Pittsburgh
The Center for the Celebration of Creation
Untours

Rhode Island
American Lung Association in Rhode Island
Conservation Law Foundation
Environment Rhode Island
People's Power & Light
ProsperityForRI.org
Rhode Island Thoracic Society

South Carolina
American Lung Association in South Carolina
Coastal Conservation League
Conservation Voters of South Carolina
New Rosemont Homeowners Association
South Carolina Native Plant Society
Southern Alliance for Clean Energy
Trinity Episcopal Church, Abbeville, SC

South Dakota
American Lung Association in South Dakota
Dakota Resource Council
Environmental Law & Policy Center
Western Organization of Resource Councils

Tennessee
American Lung Association in Tennessee
Southern Alliance for Clean Energy
TN Conservation Voters

Texas
Air Alliance Houston
American Lung Association in Texas
Argyle-Bartonville Communities Alliance
Dallas Downriver Club
Downwinders at Risk
Environment Texas
Flower Mound Defense Fund
Old Town Neighborhood Association
Texas League of Conservation Voters

Utah
American Lung Association in Utah
Breathe Utah
Utah Chapter of the American Academy of Pediatrics
Utah Moms for Clean Air
Utah Physicians for a Healthy Environment
Wasatch Clean Air Coalition

Vermont
American Lung Association in Vermont
Conservation Law Foundation
Idle-Free VT Inc.

Virginia
American Lung Association in Virginia
Center for Health, Environment & Justice
Chesapeake Climate Action Network
Environment Virginia
Health Care Without Harm
National Association for Medical Direction of Respiratory Care
The Nature Conservancy
Virginia League of Conservation Voters

Washington
American Lung Association in Washington
Climate Solutions
Earth Ministry/Washington Interfaith Power & Light
Environment Washington
World Temperate Rainforest Network

West Virginia
American Lung Association in West Virginia
Northern WV Occ. & Env. Evaluations, LLC

Wisconsin
American Lung Association in Wisconsin
Environmental Law & Policy Center
Milwaukee Latino Health Coalition
Wisconsin Asthma Coalition
Wisconsin Environment
Wisconsin League of Conservation Voters

Wyoming
American Lung Association in Wyoming
Western Organization of Resource Councils
Wyoming Conservation Voters
Wyoming Outdoor Council

American College of Preventive Medicine • American Lung Association • American Public Health Association •
American Thoracic Society • Boston Public Health Commission
Hepatitis Foundation • Mid-Atlantic Center for Children's Health & the Environment
National Environmental Health Association • Prostate Cancer Awareness Project • Trust for America's Health

February 15, 2011

U.S. House of Representatives
Washington, DC 20515

Dear Representative:

We write in strong opposition to H.J. Res. 9, which would roll back limits for mercury and other toxic air pollutants from cement plants. Mercury is particularly dangerous to developing fetuses and young children. The bill, filed pursuant to the Congressional Review Act, would permanently block implementation of these standards – and would permanently bar adoption of similar ones.

As the American Academy of Pediatrics notes, "mercury in all of its forms is toxic to the fetus and children, and efforts should be made to reduce exposure to the extent possible to pregnant women and children as well as the general population."* Cement plants are the third-largest source of human-caused mercury emissions; rolling back mercury standards for such plants would be a step in exactly the wrong direction.

Under the standards, which the Environmental Protection Agency issued in final form in September 2010, cement plants emissions of mercury and other pollutants would fall dramatically, reducing mercury pollution by 16,400 pounds, other hazardous air pollutants by 5,200 tons, and acid gases by 5,900 tons. In addition, EPA calculates that the standards would greatly reduce fine particulate pollution from cement plants, preventing up to 2,500 premature deaths annually and saving up to $18 billion in human health costs.**

We strongly urge you to vigorously oppose this legislation, as well as other attempts to undercut the nation's environmental and health protections.

Sincerely,

American College of Preventive Medicine
American Lung Association
American Public Health Association
American Thoracic Society
Boston Public Health Commission
Hepatitis Foundation
Mid-Atlantic Center for Children's Health & the Environment
National Environmental Health Association
Prostate Cancer Awareness Project
Trust for America's Health

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*http://aappolicy.aappublications.org/cgi/reprint/pediatrics;108/1/197.pdf
**http://www.epa.gov/ttnecas1/regdata/RIAs/portlandcementfinalria.pdf

Mr. WHITFIELD. Thank you. Mr. Krouskop, you are recognized for 5 minutes.

STATEMENT OF DIRK KROUSKOP

Mr. KROUSKOP. Chairman Whitfield, Ranking Member Rush, and members of the subcommittee, my name is Dirk Krouskop and I am the Vice President of Safety, Health, and the Environment at MeadWestvaco. MeadWestvaco is a global leader in the packaging industry, producing high quality paperboard and plastic packaging, in addition to operating school and office supply and specialty chemical businesses. We operate and market our products globally with approximately half of our 17,500 employees based in the United States. At MeadWestvaco, we are proud of our leadership and sustainability, and our longstanding record of environmental stewardship.

Today I am here representing MeadWestvaco; however, we are also members of a number of organizations that represent manufacturers whose members share concerns similar to those that I am expressing today on behalf of MeadWestvaco. I would like to thank you for the opportunity to discuss the challenges that manufacturers face in boiler MACT and other related rules. We applaud this subcommittee for your commitment to ensuring that laws are implemented in a reasonable and fair manner. Environmental legislation has produced significant improvements in air and water quality over the past several decades, and improvements year over year continue.

What has also changed and at an increasing pace in recent years is the global nature of our businesses. Today, many businesses, including MeadWestvaco compete globally. We must produce cost competitive products that can be sold into global markets; we must compete against products from overseas; and we must compete in global markets for the capital required to meet regulatory demands, and hopefully still be able to grow our businesses.

A key issue for the committee's consideration is the cumulative effect of many new regulations which are confronting manufacturers like MeadWestvaco nearly simultaneously. Paper and wood products manufacturers are facing over 20 major regulations from EPA's Clean Air Act program alone. The pace and volume of regulation is not sustainable not only for the regulating community, but also for the government.

I have attached a diagram to my written testimony that shows the clean air regulations in the pipeline that will affect forest products manufacturers. This picture gives you an idea of the regulatory train wreck from just one EPA program, and it doesn't even take into account the hundreds of other regulations we must comply with every day.

As detailed in my written statement, this regulatory environment increases our costs, makes us less competitive on a global basis, and ultimately results in lost jobs.

The forest products industry, like so many other manufacturers, has been hit hard by the economic crisis. Since 2006 when the housing downturn began, the forest products industry has lost 31 percent of its workforce, nearly 400,000 high-paying jobs, largely in small rural communities that can least afford to lose them. The closing of a mill in a small town has a severe ripple effect when that mill is the largest employer and a major contributor to local taxes and community programs.

Here are a few of the many regulations we are concerned about. EPA's recently finalized Boiler MACT rules will cost our industry well over $3 billion, and continues to ignore what real world best performing boilers can achieve. While Congress authorized EPA to adopt a health-based approach to target controls for certain emissions below the health threshold, EPA decided not to use this authority and reversed its previous precedent.

EPA is also considering redoing the Pulp and Paper MACT issued a decade ago, even though MACT is supposed to be a one-time program. This could add another $4 billion in capital costs beyond Boiler MACT.

The National Ambient Air Quality Standards Program has greatly reduced emissions of criteria pollutants, yet further tightening is underway. Even before the latest ozone standard is fully implemented, EPA is tightening still further, 2 years ahead of the statutory schedule. Collectively, the revisions of all the National Ambient Air Quality Standards rules could cost the forest products industry over $8 billion in capital costs.

These constantly changing air quality regulations impede rational, long-term decisions about capital spending, particularly for projects that do not return profits to the bottom line.

So what are we asking? Well, we applaud the subcommittee's effort to address the impacts of EPA regulations, and we believe Congress needs to act. As you know, EPA requested from the court an extension of a deadline for finalizing the Boiler MACT rules to get them right. The court did not grant this request. We would respectfully request that Congress act to stay the final Boiler MACT rules until EPA does get it right, reset the date for defining resources, allow facilities more time to comply, clarify that renewable and recyclable materials are traditional fuels, and ensure that the rules are achievable and less burdensome.

We also urge this committee to continue its efforts to shine light on the impact of EPA regulations facing manufacturers over the next decade. The threat of continued erosion of global economic competitiveness in the United States is real. Contributing to transparency and analysis of the impacts of regulations on the United States is critical to a future healthy and robust economy.

In summary, we know that the current wave of pending new regulations is unsustainable. This uncertain regulatory environment not only costs current jobs, but it also prevents new jobs from being created. The tangled web of rules impedes investment and too often leads to the decision not to invest, or companies simply invest overseas. Others roll the dice, hoping today's rules will change by the time their project is completed. Investments in energy efficient projects, mill modernization programs, and new biomass boilers already have been affected by rules such as Boiler MACT. Unfortunately, it is easier to see the jobs that are lost after the fact, but the greatest damage may be unknowable. The projects never built, the products never made, the jobs never created.

Thank you for listening, and for your willingness to help.

[The prepared statement of Mr. Krouskop follows:]

Statement of Dirk J. Krouskop
Vice President, Safety, Health and Environment, MeadWestvaco
House Subcommittee on Energy and Power
Hearing on Recent EPA Rulemakings Relating to Boilers, Cement Manufacturing Plants, and Utilities.
April 15, 2011

Chairman Whitfield, Ranking Member Rush, and Members of the Subcommittee, my name is Dirk Krouskop and I am the Vice President of Safety, Health and Environment with MeadWestvaco. Thank you for the opportunity to testify on this very important issue to MeadWestvaco, the manufacturing sector in general and its employees.

MeadWestvaco is a global leader in the packaging industry, with annual revenues of $6 billion, producing high quality paperboard and plastic packaging for consumer products used by many major brands worldwide. We also are the leader in school and office supplies. Finally, we operate a specialty chemical business which utilizes forest byproducts to produce materials used in auto emission controls and road paving.

Approximately half of our 17,500 employees are based in the United States where we have facilities in 25 states. We also operate in 30 countries and market our products to customers in more than 100 nations worldwide. Across all of our businesses we work hard to be leaders in sustainability. At MeadWestvaco, we are very proud of our record which includes recognition as the Dow Jones Sustainability Index global leader in the containers and packaging segment for the past 6 years. MeadWestvaco was also named to the Carbon Performance Leadership Index in 2010, the first year of its existence, by the Carbon Disclosure Project. We were one of only fourteen S&P 500 companies who have demonstrated commitment to strategy, governance, stakeholder communications and carbon emissions reduction. We are proud of our accomplishments ---from our forests to plants and offices to the communities in which we live and operate. This is a core value that we embrace in all we do.

MeadWestvaco is also affiliated with several organizations whose member companies have significant interest in the topic of today's hearing, including the American Forest and Paper Association (AF&PA), the Industrial Energy Consumers of American (IECA), the National Association of Manufacturers (NAM) and the Council of Industrial Boiler Owners (CIBO). Today I am here to testify on behalf of MeadWestvaco, focusing on the Boiler MACT rules and the associated regulatory burden and costs to manufacturing companies, especially those who operate biomass and coal fired boilers such as those prevalent in the forest products industry. I am also here to share the concerns of the National Association of Manufacturers regarding the Boiler MACT rules. The NAM reports that the EPA's final Boiler regulation would apply to nearly all sectors of the association's membership, including the chemical, auto, metalworking and petroleum refining sectors. These new standards for industrial boilers would have an immediate negative impact on these manufactures' global competitive position and impede the ability of these companies to create jobs at this critical juncture of recovery for the American economy.

We applaud this subcommittee and others for taking seriously the role of oversight of the Agency's implementation of the laws that Congress has enacted. Although environmental legislation has produced significant improvements in air and water quality, many of these laws were enacted decades ago. Over the many years since enactment, business in our sector has become increasingly global in nature and now much of our competition comes from overseas.

A key issue for this committee's consideration is the cumulative effect of the many new regulations which confront manufacturers nearly simultaneously. Under the Clean Air Act alone, the forest products sector is currently facing over twenty new regulations, including Boiler MACT, which will have a dramatic impact on the cost structure and thus the long term viability of many facilities within our industry. It also needs to be noted that as we look ahead it can be reasonably predicted that complying with one rule could be contradictory to what will be required to comply with another subsequent rule. For example, taking the necessary steps to comply with the Carbon Monoxide standard recently issued under Boiler MACT could put in jeopardy compliance with NOx emission limits in effect today and those more stringent standards contemplated in the future. This example is simply about compliance with emission standards. Needless to say the costs, both operating and in potential capital that could ultimately become stranded, are significant.

Attached to this testimony is a diagram of Clean Air Act regulations in EPA's pipeline that will affect forest products industry manufacturing facilities. Other manufacturing sectors would produce a similar diagram. I should note that the Appendix to this statement also includes many other areas of concern, including EPA regulations on waste, greenhouse gases, and water.

In most cases identified below, significant capital investment will be required for equipment needed to meet the regulation. This diverts scarce capital that might otherwise go to growth in manufacturing capacity and the attendant production of jobs. The suite of potential clean air regulations could well discourage the expansion or upgrade of existing forest products industry facilities in the U.S.

State of the Industry

The U.S. forest products industry – both paper and wood products-- has struggled with trying economic times for more than a decade. Since 2006, the forest products industry has lost 31 percent of its workforce-- nearly 400,000 high-paying jobs which are located primarily in small rural communities that can least afford the employment losses.

U.S. production of paper and paperboard declined 10% between 2007 and 2010. While we experienced some rebound in market demand in 2010, the decline reflects the still-weak economy, competition from overseas, and cost pressures, including government regulations.

As a result, the paper industry has earned its cost of capital in only two of the past ten years, and has been forced to restructure to meet global competitive pressures. Paper and allied products industry employment has declined by 58,000 positions, equal to 13 percent of the industry's workforce as 52 paper mills have permanently closed their doors just since 2007.

According to a research paper by the Economic Policy Institute, for every 100 paper industry jobs, an additional 325 jobs are sustained in other industries resulting from the purchase of supplies and the re-spending of worker incomes.[1] Hence, the 58,000 jobs lost in the paper industry suggest total job losses inside and outside the industry of over 250,000.

The wood products side of the industry is also facing huge economic challenges due to the collapse of homebuilding, the leading end-use market for wood building products. Employment in the wood products manufacturing sector has declined by 31 percent (152,000 jobs) since the end of 2007, and by 45 percent (280,000 jobs) since the end of 1999. It will likely take years for wood product markets to fully recover.

Since many wood and paper mills are located in rural areas where these high-paying jobs cannot be replaced, the effect of these job losses on local rural communities can be especially devastating. The closure of a mill in a small town has an enormous ripple effect when that mill is the largest employer and a major contributor to local taxes and community civic programs.

The job losses that have occurred in the forest products industry represent only a portion of the total loss of manufacturing jobs in the United States over the past decade. In the period 2000 through 2010, there was a loss of 5.7 million manufacturing jobs. In other words, the Nation has one-third fewer manufacturing jobs today than existed in 2000. Using a simple three to one ratio of non-manufacturing jobs created for every one manufacturing job, nearly 23 million jobs were lost to the American economy over the past decade. A chart which shows the historical trend in manufacturing job losses in the United States over the past ten years is attached to this testimony.

Government regulations that are not cost-effective exacerbate what is already a bad situation. For instance, a recent study conducted for AF&PA by Fisher International concluded that several upcoming Clean Air rules other than Boiler MACT would cause 62 additional mills to close and 26,778 paper industry jobs to be lost. If supplier jobs and jobs associated with the re-spending of worker incomes are included, total job losses could reach nearly 114,000. Moreover, the recently announced "final" boiler MACT rules would likely cause thousands of additional job losses in the forest product industry and its related supply chain.

Job losses due to regulations can have long-term impacts on workers' lives as well as on the U.S. economy. Economist Jacob Kirkegaard of the Peterson Institute for International Economics observed that workers' skills atrophy as a result of unemployment because they are less able to keep up with developments in their field.

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[1] Economic Policy Institute, "Updated Employment Multipliers for the US Economy" (2003).

And if the worker shifts to a new field, the human capital associated with the former occupation may wind up being of little or no use.[2]

The Boiler MACT Rules

The "Boiler MACT" is a regulation issued under the Clean Air Act Amendments of 1990. The statute requires that EPA regulate hazardous air pollutants from emission sources, including industrial boilers, using maximum achievable control technology ("MACT"). Boilers use various fuels at industrial, commercial and institutional facilities to generate steam, heat, and/or electricity to power essential manufacturing processes.

On March 21, EPA published in the Federal Register the final Boiler MACT rule and three related rules.[3] The new Boiler MACT regulation is a replacement for an earlier regulation that was vacated in 2007 when a court determined that elements of the rule were flawed. EPA then entered into a consent decree with Sierra Club which put in motion the complete rewrite of the rule. In June 2010, EPA issued a proposed version of the regulations that more than 260 elected officials publicly called on EPA to change significantly to make the rule achievable and affordable for facilities that support family-wage jobs across the country.

Although there were some improvements from the proposed rules, the final rules are still a long way from being achievable or affordable for our industry. Although most boilers already are well controlled for key pollutants, EPA's Boiler MACT rule will require more than 90% of boilers to make significant changes. For the forest products industry, our initial capital cost estimate of the final rule is well over $3 billion. By comparison, forest product industry pre-tax profits averaged $3.6 billion from 2008-2010. Unfortunately, as technical experts delve deeper, their concerns about achievability and affordability have only grown. For example, while the limits for mercury and hydrochloric acid became more reasonable for biomass boilers since the proposed rule, the carbon monoxide limits for stoker fired biomass boilers actually became more stringent. When burning wet biomass, it will be very challenging, even with the combustion improvements EPA assumes necessary, to meet the more stringent limits.

The final rule still inadequately accounts for the tremendous variability among boilers. EPA continues to ignore what real-world, best performing boilers can achieve over the range of normal operating conditions. For example, the new boiler limits are so stringent that the only viable fuel from the perspective of being able to guarantee compliance with emissions limits will be natural gas. The rule should ensure that limits are technically achievable, that new boilers are encouraged to use a broad range of fuels and that new investment in state-of-the-art boilers is not inhibited.

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[2] (See 'Economists Suggest Long-Term Unemployment Holds Hidden Dangers," 11/19/2010) www.job.com/career-advice/employment-news/economists-suggest-long-term-unemployment-holds-hidden-dangers.html

[3] In addition to Boiler MACT, EPA is finalizing three related rules: the Commercial and Industrial Solid Waste Incinerator (CISWI) rule (setting limits for non-hazardous solid waste incinerators); the definition of Non-Hazardous Secondary Materials (a Resource Conservation Recovery Act rule determining which materials are wastes and thus covered under the CISWI rule when burned); and Boiler GACT (Generally Achievable Control Technology for boilers at smaller sites).

We think EPA made the right choice in relying on cost-effective work practices for more boilers in the final rule, such as gas units, biomass boilers at small mills and back-up boilers, providing an affordable way to reduce emissions. However, the rule should have set flexible work practices for certain organic compounds as well. Several of these compounds are very hard and expensive to measure, their formation highly variable, and methods for control are poorly understood. The industry is not certain that it can even measure dioxin at the extremely low limits being imposed, let alone control for it.

Congress gave EPA the authority in section 112(d)(4) of the Clean Air Act to set alternative standards for pollutants with health thresholds in cases where the regular MACT limits may be "far more stringent than necessary to protect public health…". Boiler MACT is exactly the type of situation Congress had in mind when giving EPA this authority. This rule covers boilers used in numerous industries and in a wide variety of applications and settings. The economics of each setting vary significantly and impact a broad cross section of the economy. Although Congress provided EPA with the statutory authority to target and adjust controls for certain emissions where risks are low, EPA has failed to use this authority despite repeated requests by hundreds of members of Congress, Governors and stakeholders.

Any reservations about setting health based emission limits have been addressed in public comments. AF&PA provided toxicological verification that several of the pollutants have health effect thresholds and suggested a way to account for any additive effects among these pollutants. The Association also challenged EPA's perspective that any risk assessments must look beyond the boilers covered in this regulation. Smaller, older biomass boilers in economically distressed sectors can't afford unnecessary state-of-the-art controls without putting continued operations and thus jobs at risk. If EPA provides a health based emission limitation for threshold pollutants such as manganese and hydrogen chloride that is set for each qualifying facility, then costs could be significantly reduced while still protecting public health. Alternatively, separate subcategories could be adopted with reasonable limits to avoid putting facilities at risk of closure.

Moreover, as more fully described below, in its final Non-Hazardous Secondary Materials rule, EPA has created a confusing and inappropriate definition for secondary materials that are solid wastes (rather than fuels) when burned, shifting many boilers under the more onerous Incinerator MACT, known as the CISWI rule. This also will cause various renewable biomass residuals to be classified as "solid waste," resulting in them being landfilled rather than being beneficially used as alternative fuels, as they traditionally have been, which is essential to the economic sustainability of some operations.

The only new boilers that may remain viable are those that burn natural gas. After many concerns were expressed about the proposed natural gas standards, EPA eventually adopted much more flexible work practices. However, the net effect may be to curtail energy options for new boilers. This not only puts all our eggs in one energy basket, but also raises serious practical problems. Many boilers simply do not have access to natural gas because the infrastructure is not there. Moreover, the economics of some manufacturers (including forest products) depend on the ability to use diverse energy sources. Our future will be jeopardized if we cannot use a diversity of fuels in our boilers because regulatory requirements effectively preclude this from being allowed.

The three years provided in the rule to comply is insufficient given the complexities of the rules. In addition, other air regulations, such as Utility MACT, implementation of the many National Ambient Air Quality Standards changes and the upcoming Transport Rule will draw upon the same engineering expertise and emissions control vendors driving up costs more than currently estimated. Facilities should be given several more years to comply to account for capital planning cycles and allow a smooth implementation of the new Boiler MACT requirements.

EPA seems to recognize the shortcomings of the final rule given the tight timeframe allowed by the Court. By acknowledging the need to reconsider parts of the rule, EPA is admitting that more work needs to be done. We agree -- EPA should make amendments to address the key outstanding issues. While this process unfolds, the rules must be stayed to prevent hundreds of millions of dollars being wasted on the wrong investments.

The date that defines a new boiler must also be reset to the date when EPA publishes the new reconsideration proposal. Under the current rulemaking, the date that defines what is a new boiler is retroactively set to June 2010. This puts those that have already made the decision to invest in new boilers in the somewhat ludicrous and certainly unenviable position of having already invested many tens of millions of dollars and are now faced with investing many millions of dollars more to meet the recently proposed rule. Although EPA has recognized the need for reconsideration of significant sections of the rule, for those now considering investing in new boilers the uncertainty associated with the current regulatory situation makes committing to the kind of investment decisions required extremely difficult at best.

We believe Congress needs to act. The rules have been strongly influenced by judicial decisions; including the short deadline EPA was given by the court to produce the March final rules. Congress needs to stay the final rules until EPA gets it right, reset the date for defining new sources, allow facilities more time to comply, clarify that renewable and recyclable materials are traditional fuels, and make sure the rules are achievable and less burdensome. EPA has the statutory discretion to answer the call from over 260 elected officials to produce rules that are achievable and affordable while both protecting jobs and public health.

Non-Hazardous Secondary Materials Rule

As part of the Boiler MACT rules, EPA promulgated definitions for non-hazardous secondary materials for the first time, which determines the materials that are considered fuels under Boiler MACT and those that are considered solid wastes, and thus, regulated under the Commercial and Industrial Solid Waste Incinerators (CISWI) rules. Because the CISWI rules are more onerous, and mills want to avoid the stigma of having their boilers reclassified as waste incinerators, many mills will stop burning solid wastes. In the forest products industry, most of these secondary materials are biomass residuals that are carbon neutral, renewable, and have been used safely for decades as fuels. In fact, they are critical to the sustainability of some mill operations. However, because the NHSM arbitrarily requires these materials to be comparable in terms of their constituents (called contaminants) to "traditional fuels" under the rule's "legitimacy criteria," they will get branded wastes. Yet, organic "contaminants" are completely combusted in boilers while other "contaminants" will be effectively controlled under Boiler MACT. In other programs, EPA and other agencies are trying to encourage the use of alternative fuels with the positive attributes of these biomass residuals to replace fossil fuels. EPA should modify its approach for classifying biomass residuals, such as resinated wood, paper process residuals, wastewater treatment residuals, and processed construction debris, as solid wastes by dropping the contaminant comparability test so more materials can be safely used as fuels and not truly wasted by being landfilled.

EPA Jobs Study on Boiler MACT

Much has been reported about the dueling jobs studies on the Boiler MACT regulations. The EPA recently released a Regulatory Impact Analysis, which indicated that the final Boiler MACT rule would range from destroying 4,100 jobs to creating 8,500 jobs. The midpoint of the range was 2,200 jobs created. EPA's jobs analysis was based on a 2002 paper by Morgenstern, Pizer and Shih published in the *Journal of Environmental Economics and Management*.

In using the Morgenstern study, the agency relied on a model that was predicated on data from the1979-1991period. While the Morgenstern findings may have indeed been relevant for the 1980s when people had to use paper and foreign competition was not nearly as keen, it needs to be rethought and updated to reflect today's reality. With increased foreign competition, electronic competition, and a weak economy, the paper industry is in a far different place today than it was in the 1980s. The EPA's approach fails to recognize that reality. We believe an updated methodology should be used for assessing job losses or gains reflecting today's global competitive factors.

As explained earlier, the U.S. forest products industry has already lost a large percentage of its workforce. If more mills are forced to close their doors permanently we will lose additional high paying, tax generating jobs. Exports will drop and imports will increase since no other country is contemplating requirements this extreme.

Other Near-Term Clean Air Act Regulations

- Pulp and Paper MACT and Residual Risk:

EPA is considering redoing the Pulp and Paper MACTs issued a decade ago, even though MACT is supposed to be a one-time program. Given the stringency and unachievability of the Boiler MACT, we are very concerned that a similar approach will lead to a rule with over $4 billion in additional capital costs. EPA's obligations are to look at the health risks that remain after MACT, not a total MACT do-over. We believe that the original MACTs reduced emissions significantly (and at great expense) to the point where remaining risks are dramatically reduced and now quite low based on the extensive information the industry has provided EPA. In addition, any plans to regulate hydrogen sulfide (which could cost close to $3 billion) should be abandoned, since emissions are below levels of concern. Given the accelerated consent decree schedule EPA agreed to for issuing a rule, EPA should focus its resources on making a "Residual Risk" determination using reasonable risk assessment methods, data and assumptions, taking costs into account as Congress required in the Clean Air Act.

- National Ambient Air Quality Standards (NAAQS):

The National Ambient Air Quality Standard (NAAQS) program has greatly reduced emissions of criteria pollutants. Air quality has improved dramatically for all six NAAQS pollutants at significant cost to industry bringing many areas into attainment – and more reductions are on the way under existing programs. The forest products industry has been part of these reductions, reducing sulfur dioxide and nitrogen oxides by between 25 and 35 percent in the last fifteen years alone, as well as cutting emissions of hundreds of thousand of tons of particulate matter (PM) and volatile organic compounds (VOCs).

Yet, further tightening of the NAAQS is underway, with the short-term NOx and SO_2 NAAQSs finalized last year and the ozone and PM NAAQS scheduled for this year. Collectively, these NAAQS revisions could cost the forest products industry over $8 billion in capital costs. Of equal concern is the permitting gridlock caused when mills cannot satisfy modeling criteria for plant improvements (even ones that reduce emissions), preventing mill modernization and damaging competitiveness. EPA's standards are so close to background levels for some pollutants that even the dust from roads around a mill are enough to exceed modeling parameters and potentially stop permit revisions.

Under the Clean Air Act, Congress directed EPA to consider, every five years, whether any changes are needed to the NAAQS. In March 2008, EPA replaced the 1997 ozone standard with a new, more stringent standard. Even before that standard will be fully implemented, EPA is considering tightening it further -- two years ahead of the usual statutory schedule. Last month, 38 newly elected Congressmen wrote to Administrator Jackson citing concerns about the impact on jobs and the economy and asking that she withdraw the proposed ozone rule and instead conduct a full science review under the usual five year schedule. A similar bipartisan letter signed by 51 House Members was sent to the Administrator last November. Given the significant economic burden imposed by the ozone NAAQS on the forest products industry and the still fragile economy, we agree that deferral is warranted.

- Cluster MACT Reopening:

EPA finalized Maximum Achievable Control Technology (MACT) rules for paper mills in 1998 and 2001 but has been petitioned by environmental groups (ENGOs) to make them more stringent. The Clean Air Act created MACT as a one-time program, and EPA has met its obligation for paper mills. EPA should focus on programs that are required under the Act and not put additional burdens on the paper industry by reopening the Cluster MACTs.

- Wood MACT:

In 2004, EPA promulgated the Plywood and Composite Wood Product MACT (so called Wood MACT) which required 90% reductions in certain hazardous air pollutant (HAP) emissions. In 2007, the D.C. Circuit Court of Appeals rejected a risk-based option that could have allowed wood product mills to avoid controls where risks were demonstrated to be safe. That same court concluded that emission standards should be set for all process equipment at wood product mills. Unfortunately, gas-fired control devices (incinerators) have been widely installed to meet Wood MACT and other Clean Air Act programs such as New Source Review. These incinerators not only consume $100Ks of fuel each year and cost millions to install, but also emit greenhouse gases and NOx largely in "NOx limited" areas. A life cycle inventory documented the negative nature of these systems, concluding that they do more harm than good. To make matters worse, more incinerator controls may be required in the future for the remanded units covered by Wood MACT. EPA should explore alternative policies that eliminate the need for existing and additional gas fired controls, such as use of work practices and limits that can be met using biological control systems.

Numerous other EPA rules on greenhouse gases, solid waste, and water are attached to the appendix to this testimony.

The TRAIN Act

We applaud the subcommittee's effort to shine light on the impacts of EPA regulations and we encourage passage of the "Transparency in Regulatory Analysis of Impacts on the Nation Act of 2011". The threat of continued erosion of global economic competitiveness of the United States in the face of an unprecedented onslaught of new regulations over the next decade cannot be dismissed. This would be true in an economy that is healthy and robust. It is even more essential in an economy that still struggles to recover and retain existing jobs; much less create new jobs.

The completion of the analysis contemplated in the TRAIN Act is particularly critical to companies whose operations are both energy intensive and trade sensitive. As has been pointed out elsewhere in this testimony, faced with ever increasing requirements for capital investment in pollution controls, the operating costs associated with these controls, and the uncertainty created by the current EPA regulatory agenda, many companies who cannot successfully compete in global markets will either be faced with shutting down facilities and going out of business or moving production offshore. In either case, high paying jobs will be lost and a ripple effect will be created throughout the supply chain and surrounding communities. When these jobs cannot be replaced, many communities, especially the rural towns where many Forest Product industry facilities are located, will inevitably reach a tragic economic "tipping point".

We believe that completion of this analysis, followed by careful consideration of the results and ultimately implementing actions by policymakers is critical to the future health of companies like MeadWestvaco and United States manufacturing in general. We encourage the subcommittee to move to swift passage of the TRAIN Act while legislatively staying significant rulemakings, such as Boiler MACT, until such time as the full economic impact of the cumulative regulatory burden facing the regulated community is understood and appropriate policy is established to protect the global competitiveness of the United States.

Conclusion

We know that the current wave of regulations is unsustainable. Living with such an uncertain regulatory environment not only costs current jobs, but also prevents new jobs from being created.

Companies frequently find themselves tangled in a web of rules that result in the decision to simply not make an investment because of the uncertainty of the regulatory process – or they decide to invest overseas. Others roll the dice, hoping that the rule they are making decisions under today will still be in place when their project is completed. When regulations such as the Boiler MACT rules and changes in the National Ambient Air Quality Standards create such uncertainty and are not affordable or achievable, investing in an energy efficiency project, modernization programs, or a new biomass boiler can be very risky, preventing job creation in rural communities that desperately need it.

Unfortunately, it is easier to see the jobs that are lost after the fact. But the greatest damage may be unknowable -- the projects never built, the products never made, the jobs never created, or the entrepreneurial ideas drowned in the sea of red tape.

All these concerns about the future global competitiveness of the United States, the need to not only create but also to keep existing jobs, and the risks to economic recovery must be considered against the backdrop where environmental quality in the United States is the best it has been in decades – and continues to improve. This is due in part to existing regulatory programs that are in full force today and still creating gains in environmental quality without further regulatory actions. This is also due in no small part to the fact many companies including MWV recognize that being a responsible global citizen, that satisfying our customers, and caring for the communities in which we operate is simply good business. It is about creating a business that is sustainable.

In summary, we would encourage the subcommittee to advance legislation to accomplish the following:

1. Require an analysis of the economic impact of the cumulative burden of rules that either EPA has proposed to modify and/or that EPA has a statutory obligation to consider over the coming decade.
2. Legislatively stay the Boiler MACT and the three related rulemakings (effectively stopping the compliance clock which is now ticking) and give EPA the time they themselves said was necessary to properly develop the rules. In no case should EPA promulgate final Boiler MACT rules until such time as the above economic analysis is completed, fully considered and appropriate policy is developed.
3. At such time as the Boiler MACT rules are finalized, direct EPA to extend the time to comply with the complex requirements of the rules so affected boiler operators can adequately plan the significant capital investments that may be required.
4. At such time as the Boiler MACT rules are finalized, provide direction to EPA that these rules should use specific approaches that add flexibility, encourage use of a wide variety of fuels and make the rules achievable through mechanisms available in the Clean Air Act as was the intent of Congress when the Act was passed. Items covered should include:
    a. Define various biomass residuals, tire derived fuel, and on-spec used oil as traditional fuels (not solid wastes) under the Non-Hazardous Secondary Material rule and exclude gases in pipelines, ducts or vents from being regulated as solid wastes
    b. Provide for utilization of work practices for certain organic compounds
    c. Establish emission limits for existing sources (not by pollutant) for each subcategory considering various variability factors of best performing boilers
    d. Establish emission limits for new sources that are achievable for state of the art boilers for each subcategory considering various variability factors
    e. Adopt Health Based standards without unnecessarily complicated procedures for HCl and manganese (in conjunction with a total select metals limit) that does not jeopardize the existing Particulate Matter and HCl surrogate limits

Thank you for taking the time to listen to some of the many regulatory challenges facing companies like MWV and for your consideration of taking strong action to maintain the global competitiveness of United States manufacturers.

APPENDIX
ADDITIONAL EPA REGULATORY ACTIONS SIGNIFICANTLY AFFECTING THE FOREST PRODUCTS INDUSTRY

Greenhouse Gas Regulations

- EPA Greenhouse Gas (GHG) Regulation Under the Clean Air Act:

Effective January 2, 2011, EPA's regulation of GHGs from stationary sources under the Prevention of Significant Deterioration (PSD) and Title V programs broke with longstanding precedent for biomass carbon neutrality, treating the combustion of biomass identically to the combustion of fossil fuels. EPA chose to treat biogenic emissions the same as emissions from fossil fuel in the Tailoring Rule. Two-thirds of the energy needs of forest products mills are met through wood biomass residuals. Counter to Administration objectives, EPA's treatment of biogenic emissions ignores the renewability of the resource and stymies investment in renewable energy. EPA subsequently postponed regulation of biogenic CO_2 emissions for three years while it conducts a study of the science and technical issues associated with these emissions. EPA plans to develop its own GHG accounting framework for biogenic emissions, differentiating different types of feed stocks based on their net emissions to the atmosphere over business as usual levels, specific time frames and geographic regions. This accounting framework will, in effect, regulate and significantly limit the use of forests and other biomass for renewable energy. There is currently a significant scientific foundation and policy precedent to support the carbon neutral status of biomass combustion. U.S. EPA and Forest Service data unequivocally show that land in the U.S. is a significant net sink for CO_2 – not a source that should be regulated. Furthermore, Congress, not EPA, should determine renewable energy policy for the country. EPA should uphold the principle of carbon neutrality and leave renewable energy policy to Congress.

- EPA Greenhouse Gas Mandatory Reporting Rule:

Facilities must report their 2010 GHG emissions beginning September 30, 2011. Unlike other regulations, EPA has not allowed facilities to propose alternative methods for calculating emissions or allowed *de minimis* emissions levels under which reporting is unnecessary. This inflexibility makes the rule more expensive to implement than is necessary. EPA has also proposed to make public individual facility inputs to GHG emissions calculations and production data which are traditionally considered confidential business information. Making such energy and production data available to the public will enhance the ability of foreign and domestic competitors to gain insight into production costs and will potentially impact pricing decisions in the marketplace.

Waste Regulations:

- Coal Combustion Residuals:

EPA has proposed to regulate coal combustion residuals from the electric utility industry as either hazardous or non-hazardous solid waste. Although the forest products industry would be exempt under the current proposal, states have indicated they would not differentiate between utility and non-utility residuals. EPA could regulate these materials under the non-hazardous waste provisions and modify the proposal to make those requirements consistent with the degree of harm posed by such residuals. Further, strict regulation under the hazardous waste regulations is not necessary to address the risks posed by coal combustion residuals. The forest products industry and other industries will pay increased electricity costs passed on by utilities if EPA chooses the hazardous waste option.

Water Regulations

- Florida Nutrient Standards:

Despite the fact that the State of Florida was making significant progress establishing its own nutrient standards, EPA promulgated extremely stringent numeric nutrient criteria for nutrients (nitrogen and phosphorous) for certain Florida waters based on a methodology that is not scientifically defensible. Stakeholders have estimated compliance with the rule will cost billions of dollars and will require expenditures for cleaning up waters that are not impaired. EPA states that it does not intend to take over other state nutrient programs and promulgate federal numeric nutrient criteria in those states. Nonetheless, EPA has indicated that the Florida methodology should be viewed as a national precedent, and EPA is forcing other states to adopt numeric criteria, while also limiting implementation options. EPA should revise the methodology to better account for the lack of a stressor/response relationship in its data for certain waters and should allow states more flexibility in implementing the criteria.

- Cooling Water Intake Structures (CWIS) Rulemaking:

On March 28, 2011, EPA issued a 413 page proposed CWIS rule applicable to certain utilities and manufacturers, including the pulp and paper industry. We are still analyzing the proposal to determine its impacts, but one thing is certain—many more industry facilities will face CWIS requirements in their water permits than would have been the case under the rule applicable to these facilities issued in 2006 (EPA is revising the rules in light of litigation, including a Supreme Court ruling). At that time, EPA determined that the costs of national categorical standards applicable to a more limited number of facilities would be "wholly disproportionate to the benefits." Yet in this proposed rule, EPA would regulate the CWIS of much smaller facilities, capturing a much larger segment of the industry within the scope of the rule.

- "Waters of the U.S." Guidance:

For nearly a decade beginning in 2002, legislation has been introduced in the House and Senate that would fundamentally alter the scope of the Clean Water Act and expand federal agency Clean Water Act jurisdiction. None of the bills ever came to a vote in either Chamber, and while one committee did consider a proposal, the measure died and was never brought to the floor. The Administration is now developing guidance that addresses similar issues raised in the bills; press reports providing a draft of the guidance strongly suggest that the Environmental Protection Agency (EPA) and the U.S. Army Corps of Engineers intend to significantly expand their regulatory control over many waters, including waters now considered entirely under state jurisdiction. The Administration should not legislate by guidance. At a minimum, this issue should be addressed in rulemaking, as opposed to guidance.

- Analytical Method for Polychlorinated Biphenyls (PCBs):

Polychlorinated biphenyls (PCBs) are a "legacy" pollutant; production was banned by Congress and EPA decades ago. However, PCBs in extremely low levels are ubiquitous in the environment. EPA has proposed an analytical test method that purports to measure in the very low range of parts per quadrillion, which is below the national EPA standard. Once the method is final and dischargers must use it for compliance, many municipal and industrial dischargers will find PCBs in their effluents at levels above the national standard. This will ultimately lead to permit limits with which compliance will be either impossible to achieve or unreasonably expensive. EPA should not issue the method until it adequately responds to the scientific questions raised in comments on the proposal. EPA also should issue flexible permit implementation procedures that acknowledge and address the ubiquitous nature of PCBs.

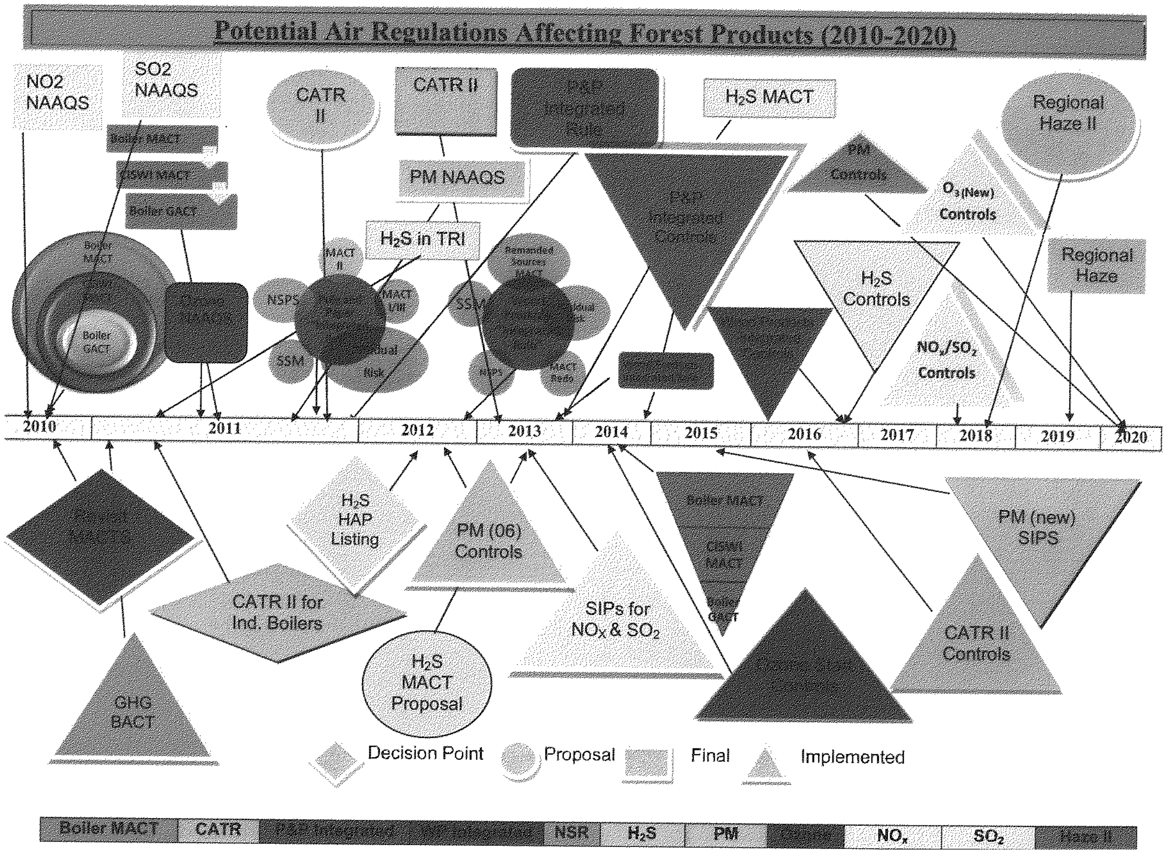
- Chesapeake Bay Total Maximum Daily Load (TMDL):

At the end of 2010, EPA issued the final TMDL for the Chesapeake Bay. A TMDL is a calculation of the maximum amount of a pollutant that a water body can assimilate and still maintain water quality standards. As part of the TMDL process, EPA usurps the states' traditional role of TMDL implementation by threatening heavy-handed measures if certain clean up milestones are not met. EPA should withdraw the measures and allow states the flexibility to implement the TMDLs, as contemplated by the Clean Water Act.

Sound Science

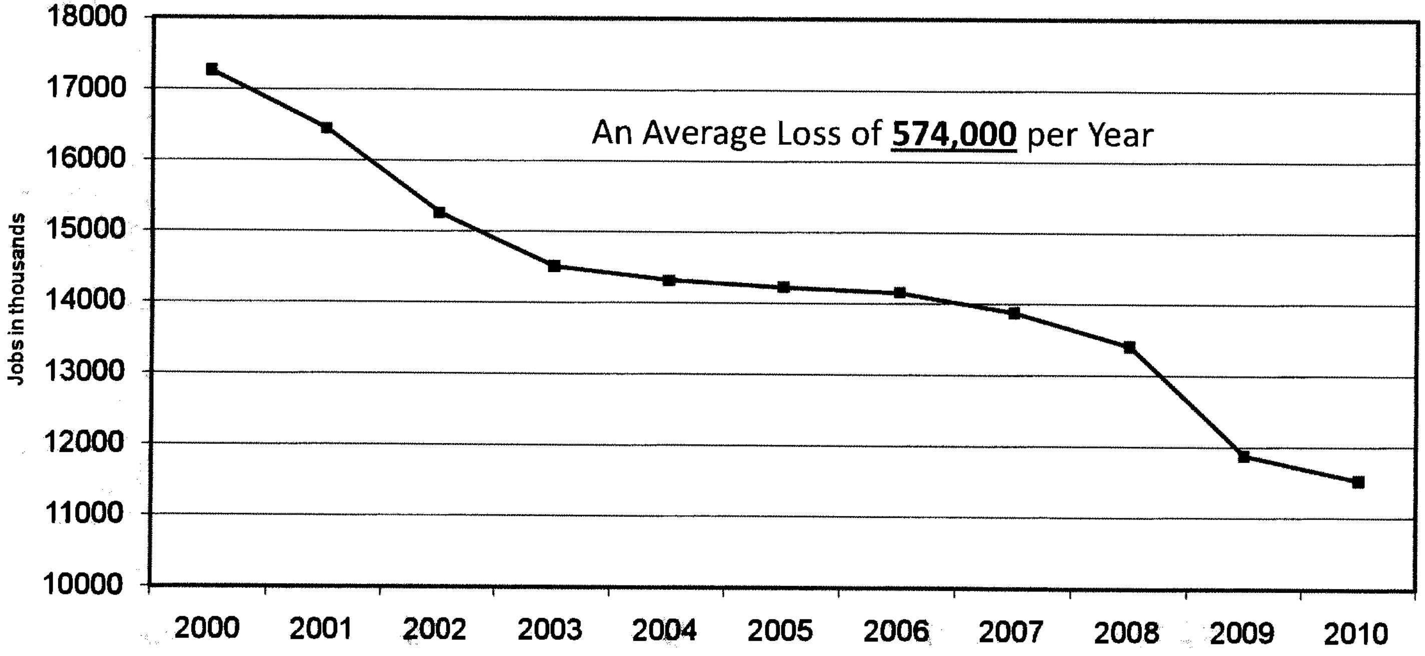
- Integrated Risk Information System (IRIS) Assessments:

As the Administration has recognized, sound science is the foundation of an effective regulatory system. In Executive Order 13563, President Obama directed that "each agency shall ensure the objectivity of any scientific and technological information and processes used to support the agency's regulatory actions." Accordingly, scientific integrity must be the backbone of EPA's IRIS assessments. Assessments for chemicals such as methanol, formaldehyde, dioxin, hydrogen sulfide, acrolein and acetaldehyde have a major impact on regulatory costs for many sectors of the economy and deserve objective and unbiased development and review.



Potential Air Regulations Affecting Forest Products (2010-2020)

U.S. Total: 5.7 Million Manufacturing Jobs (33%) Lost



An Average Loss of **574,000** per Year

Mr. WHITFIELD. Thank you. Mr. Papadopoulos, you are recognized for 5 minutes.

STATEMENT OF ARIS PAPADOPOULOS

Mr. PAPADOPOULOS. Mr. Chairman and committee members, my name is Aris Papadopoulos. I serve as CEO of Titan America, a cement manufacturer and concrete——

Mr. WHITFIELD. Would you turn your microphone on?

Mr. PAPADOPOULOS [continuing]. United States employing over 2,000 Americans. I presently chair the Portland Cement Association that represents 97 percent of U.S. cement capacity with nearly 100 manufacturing plants in 36 States and distribution in 50.

Cement is to concrete what nails are to wood. It is the glue that holds together our bridges, roads, dams, schools, and hospitals. At $6.5 billion combined revenue, we are a relatively small industry, but without us, the entire trillion dollar construction economy would come to a halt. Without cement, our already deteriorating infrastructure would continue to degrade to unsafe levels, along with our communities and quality of life.

The Great Recession hit our industry hard. Cement demand dropped in half. Profitability has been wiped out. Yet, we sought neither handouts nor bailouts. We cut costs, which sadly included more than 4,000 jobs. What remains are 15,000 well-paying jobs, with average compensation of $75,000, and a higher presentation of minorities.

This is a dynamic industry. In its century-long history, cement producers have demonstrated commitment to continuous improvement and environmental stewardship. Many of our facilities have existed for over half a century, and we have never seen any empirical data of the health impacts that Mr. Walke referred to. In fact, the only proof that EPA has presented are computer-generated models that only have helped to generate more fear.

In the decade prior to this recession, we invested tens of millions of dollars in modernizing and expanding facilities with state-of-the-art technologies that significantly cut energy intensity. Today, the U.S. has a world class cement industry, which recycles 12 million tons a year of industrial and urban byproducts like tires, fly ash, and wood chips that would otherwise be land-filled; however, recent regulations put all of this at risk.

In a time when our industry is crippled by recession, the EPA has bombarded us with multiple regulations that we believe both undermine economic recovery and damage the long-term environment. Several rules in particular pose immediate damage—danger to the industry. Referring to their acronyms, NESHAP, with a 2013 compliance deadline, and CISWI plus a companion to the definition of recycled materials threaten to destroy the industry's recycling success story.

NESHAP would cause 18 cement plants to shut down during the next 2 years. This rule as written is technically and economically unachievable, in fact, setting standards demanded by no other country in the world, even advanced European countries. The net result would be reduction of domestic capacity. When the market demand recovers, it would be met by imported cement. This means losing thousands more American jobs. Furthermore, shifting production overseas to places that have far lower standards than ours increases emissions, emissions that EPA itself admits will eventually travel to and fall in the U.S.

EPA needs to wake up and stop treating our industry as if we are utilities, realizing that we are not assured to return on capital, and production can move overseas. These regulations represent a hidden tax imposed on domestic production. PCA recently completed a study analyzing the impacts of EPA rules and concludes that NESHAP and CISWI rules impose a combined compliance burden of $5.4 billion in the next 4 years, equal to 85 percent of the industry's total annual sales, while increasing production costs by 20 percent. NESHAP and CISWI would force almost 25 percent of U.S. plants to shut down. We could lose an additional 4,000 jobs. Assuming economic recovery through 2015, reduced capacity will raise foreign imports to 56 percent of U.S. consumption.

These EPA rules make investing in the U.S. unattractive for overseas. In the end, neither the economy nor the environment win. American jobs and investment are lost, while more pollutants are emitted offshore. Less recycling leads to more land-filling. Dependence on foreign cement follows the road of dependence on foreign energy. The combined effects of increasing global demand for construction materials and cement being more cumbersome to import than oil will mean that shortages and price volatility become more common. This could hurt the entire construction economy, with impacts on infrastructure, housing, commerce, and jobs.

As to infrastructure, I would like to share with you some positive news. Recently lifecycle assessment research by MIT confirms that cement and concrete can play a key role in mitigating greenhouse gas emissions by building truly sustainable roads and structures. We are the battery in the sustainable infrastructure Prius. It follows that we would want to produce these strategic materials here in the U.S. to the benefit of both economy and environment.

Congress needs to step up and take back legislative ownership by establishing win-win policies like those suggested by MIT's research, create a climate that encourages rather than discourages domestic investment by taking immediate action to address onerous regulations and place a near term moratorium on more rules. With construction sector unemployment near 30 percent, Congress must craft legislation that replaces harmful regulations with policies that promote job growth, investment certainty, responsible environmental stewardship, and collaboration. This will revive private sector confidence, create good jobs for Americans, and restore economic prosperity.

Thank you for this opportunity. I would be happy to answer any questions.

[The statement of Mr. Papadopoulos follows:]

Committee on Energy and Commerce, Subcommittee on Energy and Power

Testimony of Aris Papadopoulos, Chairman of the Portland Cement Association and CEO, Titan America
April 15, 2011

Mr. Chairman and congressional committee members, my name is Aris Papadopoulos. I serve as CEO of Titan America, a cement manufacturer and concrete producer in 8 states, employing over 2,000 Americans. I presently chair the Portland Cement Association (PCA) that represents 97% of US cement capacity with nearly 100 manufacturing plants in 36 states and distribution in all 50.

Cement is to concrete what nails are to wood. It acts as the glue that builds our bridges, roads, dams, schools and hospitals. At $6.5B combined revenue, we're a relatively small industry, but without us, the entire trillion dollar construction economy would come to a halt. Without cement, our already deteriorating infrastructure would continue to degrade to unsafe levels, along with our communities and quality of life.

The Great Recession hit our industry very hard. Cement demand dropped in half. Profitability has been wiped out. Yet, we sought neither handouts nor bailouts. We cut costs, which sadly included more than 4,000 jobs. What remains are 15,000 well-paying jobs, with average compensation of $75,000.

Cement is a dynamic industry. In its 150+ year history, cement producers have demonstrated their commitment to continuous improvement and environmental stewardship. In the decade prior to this recession, it invested tens of billions of dollars in modernizing and expanding facilities with state-of-the-art technologies that significantly cut energy intensity. Today, the US has a world class cement industry, which recycles 12 million tons a year of industrial and urban byproducts, like tires, fly ash and wood chips that would otherwise be land-filled. Recent EPA rules, however, may jeopardize this practice.

In the wake of the recession, the EPA embarked on a series of rulemakings that would deliver uncertain public benefits while undermining economic recovery. Although EPA has promulgated several rules recently, there are three rules in particular that pose an immediate challenge to the cement industry. I'm talking specifically about the Portland Cement National Emission Standards for Hazardous Air Pollutants (NESHAP), which has a September 2013 compliance deadline; new standards for Commercial and Solid Waste Incinerators, or CISWI rule; and a revised definition of "solid waste," which is a companion regulation to the CISWI rule.

NESHAP, which I discussed during previous congressional forums, would close 18 of the country's 100 cement plants during the next two years. This rule as written is either technically and/or economically unachievable (*in fact setting emission standards demanded by no other country in the world!*). The net result is industry will be forced to shut down plants. When market demand for cement returns, it will be met by cement imported from other countries. The result will be the loss of more US industry jobs. Furthermore, it will also cause a net increase in pollutants from cement production in countries that have little to no regulation – and thus none of the environmental benefits of US produced cement.

These regulations truly represent is a hidden tax imposed on the domestic industry today. PCA recently completed a study analyzing the economic and environmental impacts of EPA rules and concludes that:

- The NESHAP and CISWI rules impose a combined compliance burden of $5.4B in the next 4 years, equal to 85% of the industry's total annual sales. They also increase production costs by 20%.
- The NESHAP rule will force almost 20% of U.S. plants to shut down in two years; the CISWI rule would add another 4 plant closures to the 18 closures imposed by NESHAP.
- The industry could lose 25%, or an additional 4000 jobs by 2015;
- Assuming economic recovery thru 2025, this reduced domestic cement capacity will force the U.S. to depend on foreign imports for 56% of its needs.

We conclude, that in their totality, EPA rules make investing in the U.S. unattractive compared to overseas. In the end, neither the economy nor the environment win. American jobs and investment are lost while greater amounts of pollutants are emitted offshore. Dependence on foreign cement follows the road of dependence on foreign energy. And with the combined effects of increasing global demand for construction material and cement more cumbersome to import than oil, shortages and price volatility will become more common. This could hurt the entire construction economy, with impacts on infrastructure, housing, commerce and jobs.

As to infrastructure, I must let you know that there is actually some very good news. Recent research by M.I.T. confirms that cement and concrete can play leading rules in mitigating GHG emissions and other environmental challenges. It follows that we would want to produce the materials here in the U.S. in order to reinstate win-win policies that benefit the economy and the environment.

Congress can establish win-win policies and create a climate that encourages domestic production of cement - consistent with the findings of the M.I.T. research - by taking immediate action to address onerous regulations and place a near term moratorium on more rules. Congress must craft legislation that mitigates the impacts of harmful regulations. It must replace them with policies that promote job growth, investment certainty, and responsible environmental stewardship. This will revive private sector confidence, create good jobs for Americans and restore economic prosperity.

Thank you for this opportunity to testify. I would be happy to address any questions you may have.

Mr. WHITFIELD. Thank you, Mr. Papadopoulos. We appreciate the testimony of everyone on the panel, and Mr. Waxman has come in so I am going to recognize him for 5 minutes for his opening statement.

OPENING STATEMENT OF HON. HENRY A. WAXMAN, A REPRESENTATIVE IN CONGRESS FROM THE STATE OF CALIFORNIA

Mr. WAXMAN. Thank you, Mr. Chairman, for recognizing me and for the courtesy of allowing me to give this statement out of the usual order.

Mr. Chairman, I fear that what we are seeing is another—in a series of assaults on the Clean Air Act. Chairman Whitfield announced yesterday that after the recess we will consider legislation to delay implementation of the rules to reduce toxic air pollution from utilities, boilers, and cement plants. I think that would be a major setback for clean air. If we delay these requirements to clean up toxic air pollution, our children and many other Americans will suffer serious, and in many cases, irreversible harm.

Toxic air pollution from power plants, industrial boiler, and cement plants include mercury, lead, which harm brain development in babies and children; arsenic, chromium and nickel, which cause cancer; and acid gases, which damage the lungs and contribute to asthma, bronchitis, and other chronic respiratory disease, especially in children and seniors. These facilities also emit particulate matter, which causes heart attacks, strokes, asthma attacks, hospital admissions, and premature death.

And these are big sources of pollution. Power plants are the largest source of mercury air pollution in the country. Boilers are the second largest source of mercury air pollution. And guess what? Cement plants are the third largest source of mercury air pollution in the country.

A few weeks ago when this committee reported legislation to repeal EPA's authority to reduce carbon pollution, my Republican colleagues argued that they weren't trying to weaken the Clean Air Act. They weren't trying to block regulations to stop toxic emissions, and they really do support clean air.

The chairman of the full committee said, and I quote, "EPA's ability and obligation to regulate and mitigate air pollutants like particulates that cause soot, ozone that causes smog, carbon monoxide, lead, asbestos, chloroform, and almost 200 other air pollutants would be protected and preserved."

That was last month. This month, they are directly targeting EPA's ability to protect the public from these very pollutants.

Let us be clear. Delaying these rules will hurt a large number of people, especially children. Cleaning up cement plants will avoid 17,000 cases of aggravated asthma and 1,500 heart attacks each year. Cleaning up boilers will avoid 2,600 and 6,600 premature deaths, 4,100 heart attacks, 4,400 hospital and emergency room visits each year. And cleaning up power plants will avoid somewhere between 7,000 and 17,000 premature deaths, 11,000 heart attacks, and 120,000 cases of aggravated asthma each year.

For every year these rules are delayed, thousands of Americans will die prematurely. Each year there will be over 150,000 cases of aggravated asthma, and many of them children. There will be 1.3 million additional lost days of work.

It has been 40 years since we adopted the Clean Air Act, and the three industries that are the largest sources of toxic air pollution in the country still don't have to use readily available technology to clean it up. American families have waited long enough.

Over the years when I worked on clean air, I have heard complaints about the costs of regulation more times than I can count, and every time, once we set the standards, industry applied American ingenuity and technical know-how and gets the job done, almost always below the projected costs. I have every confidence that they will do it again here.

But that won't happen if Congress repeals or blocks the Clean Air Act and stops EPA from doing its job. Some of these regulations have been delayed over a decade, and it is time that we let EPA get on with its job.

I yield back the balance of my time, and thank you so much, Mr. Chairman, for allowing me this opportunity to make my statement.

Mr. WHITFIELD. Thank you, Mr. Waxman. I think the last amendments to the Clean Air Act were 1990, and I do think Congress has a responsibility to review these acts and even make changes when necessary, and one of the reasons we have had these hearings is to try to get the testimony of different groups to see what they think about it.

I would ask Mr. Fanning and Mr. Earley, just to start off with, Mr. Waxman, who is quite familiar with the Clean Air Act, said that technology is readily available to meet this utility MACT standard, and also said that historically industry gets the job done below anticipated costs. Would you all react to that, those two statements?

Mr. EARLEY. Yes, Mr. Chairman, a couple of observations.

First of all, the Clean Air Act amendments of 1990 gave us tremendous flexibility. The concept of emissions allowances gave us the opportunity to schedule the addition of new environmental controls over a timeframe that made sense to minimize costs. This rule does not give us that flexibility. It is on a very tight timeframe that is going to drive costs up and actually strain the ability to actually install the equipment because of limitations on people and equipment and the like.

The second issue is around the availability of technology. As I mentioned in my testimony, with respect to acid gasses, the EPA assumes that dry sorbent injection technology will achieve the standards that they have set, and yet, they admit that it is based on one 3-week study on one particular type of boiler. Well, in our industry there are dozens of different boiler types and when you start injecting materials into the boiler, it does have an impact on how the system operates. We have no assurance that that technology is going to work. I don't think it is appropriate to bet millions or billions of dollars on a technology that may or may not work. It doesn't make sense.

That is why time will give us a chance to ensure whether that technology does, in fact, work, or whether those technologies are not going to work and we have to look for something else.

Mr. WHITFIELD. Mr. Fanning?

Mr. FANNING. Thank you, Mr. Chairman.

These standards that are proposed are unlike any other that has been proposed, and unlike acid rain, NOx, CARE rule, the Clean Air Interstate rule, these standards require compliance with unit specific emissions by a specified date, and that date would appear to be unreasonable.

When you think about the evaluation period that we have for this rule, 60 days for a 1,000 page proposed regulation, with 1,000 pages of underlying documentation, some of which we haven't even seen yet, it is not clear that the science being proposed will, in fact, work. There are significant disagreements that we have, nod I must say that Southern Company is by far the leader in our industry in proprietary research and development. We have deployed over $10 billion—will have deployed over $10 billion of environmental control equipment. We have developed our own environmental control equipment that performs at levels well in excess of industry standards and is able to be deployed 10 to 20 percent cheaper that what our peers are able to do.

We don't believe that some of the levels that are proposed are workable, and I think just following on what Tony said, I think that when you consider what the EPA has proposed in terms of what will be required as a result of this rule, 24,000 megawatts of scrubbers, I think the number will be more like 80. They have a very low number for what might be the retirements, and therefore will have to replace that generation to provide reliability for the benefit of our customers. We think that number is going to be 70 to 80,000. So this is a very different landscape.

Mr. WHITFIELD. OK, thank you, Mr. Fanning.

Mr. Dingell, I yield to you.

Mr. DINGELL. You are most courteous, Mr. Chairman.

This question, just yes or no. To our last two witnesses who commented here, Mr. Fanning and Mr. Earley, what you are really telling us is you need more time to see to it that the requirements that are imposed upon you will, in fact, work, and give you a solution that's in the public interest as opposed to just big expenditure money. Is that right?

Mr. EARLEY. Yes, sir.

Mr. DINGELL. Thank you. I thank you, Mr. Chairman, for your courtesy.

Mr. WHITFIELD. Thank you. Mr. Papadopoulos, in your testimony you had indicated that you would anticipate that cement factories would actually close down if this rule is implemented? Is that the case?

Mr. PAPADOPOULOS. That is correct, Mr. Chairman, especially particularly older plants——

Mr. WHITFIELD. Excuse me, bring it closer to you.

Mr. PAPADOPOULOS. Yes, particularly older plants that cannot really justify these large investments would be the ones that close down. And plants that don't have the——

Mr. WHITFIELD. How many would that be?

Mr. PAPADOPOULOS. Well, we are talking about 18 plants in just one room, and probably another two or three plants from the recent rule on waste, CISWI rule.

Mr. WHITFIELD. Well, my time is expired so I will recognize the gentleman from Illinois for 5 minutes.

Mr. RUSH. I thank the chairman.

Mr. Walke, I think it is, Mr. Fanning in his testimony is being quoted as questioning the motivation of your group—Mr. Bradley. Mr Bradley, Mr. Fanning in his testimony is being quoted as questioning the motivation of your group. He said, reportedly said that quote, "Some companies see a chance to increase their bottom lines when they reduce reliability and higher costs that EPA regulations would produce." Can you speak to the competitive advantage being realized today by companies generating electricity from coal without any environmental control? Sir, why do your companies support EPA regulations to restrict emissions from generating plants? Are you all reaping a windfall here?

Mr. BRADLEY. We've known that these regulations have been coming for over 10 years. The vast majority of companies have been planning ahead. The utility industry across the board has taken measures in advance. As I indicated, 60 percent of the capacity of the coal capability is already retrofitted with NOx emissions. It has been widely deployed. The issue around direct sorbent injection, I think, is a little outdated. We have seen in the EPA's database—this is to control acid gasses—dozens of sources that have been tested, dozens of plants that have deployed the technology, and we have been real familiar with a couple of plants that have tested the technology and believe it is going to be the key to compliance.

The baghouse fabric filter undertakings are going to be expensive, but they are doable. We think a lot of the technology can be deployed in 2 to 3 years. But I have to underscore the fact that every plant is different. Every plant has to be treated with specific engineering and design capabilities.

When it comes to reliability and reserve margins, we think the place to go to assess that is the North American Electric Reliability Council. At least in the southeast, they have projected very healthy reserve margins over the course of the future, 2014 to 2019. Given the history and the innovation that the industry has brought to the table in the past, we believe that there is no reason to introduce legislation to delay the implementation of the Utility Toxins Rule.

Mr. RUSH. Thank you.

Mr. Papadopoulos, it has been reported here, and I have a copy of an article from the News and Observer, I guess this is a local paper, about your company's "ill-advised resort" to going to court. Are you familiar with what they call a SLAPP suit?

Mr. PAPADOPOULOS. I am sorry, Congressman, I didn't understand your question.

Mr. RUSH. I said are you familiar with what they—what is being—what is termed a SLAPP suit?

Mr. PAPADOPOULOS. No.

Mr. RUSH. All right. A SLAPP suit is a suit by which a company uses litigation to try to chill public protest against a company or a project. I want to bring to your attention a report that your company sued a pediatrician, Dr. Hill, and a mom, Ms. Kayne Darrell, over statements they made opposing a proposed Titan plant near Wilmington, North Carolina, and as I understand it Ms. Darrell repeated allegations that had been published in the press and Dr.

Hill said that some people would get sick and some would die if the plant was built, and they made the statements at a county commissioner's meeting a year earlier, and at the time they spoke Titan's permit application said the plant would emit almost 1,500 tons of SO_2, over 2,000 tons of NOx, and about 350 tons of fine particulates.

What do you say about this suit?

Mr. PAPADOPOULOS. Honestly, I can't understand what you are saying, Congressman. What is your question? Maybe——

Mr. RUSH. Well, my question is, Do you believe in the Constitution?

Mr. PAPADOPOULOS. Excuse me?

Mr. RUSH. Do you believe in the Constitution?

Mr. PAPADOPOULOS. Of course.

Mr. RUSH. Do you support the Constitution?

Mr. PAPADOPOULOS. Did you ask if I swear to the Constitution?

Mr. RUSH. Do you support the Constitution?

Mr. PAPADOPOULOS. Support, yes.

Mr. WHITFIELD. Your time is expired.

Recognize the chairman of the committee, Mr. Upton, for 5 minutes.

Mr. UPTON. Thank you, Mr. Chairman. Mr. Fanning and Mr. Earley, I guess Mr. Earley, in your testimony you talked about if these utility MACT rules—if the timing stays 60 days to review, begin to see and implement 1,000 pages of regulations. You indicated in your testimony that you would be probably forced to retire nearly one-third of your plants? Is that accurate?

Mr. EARLEY. Yes, Mr. Chairman. We estimate between 20 and 30 percent of our capacity will have to be retired, if these rules stay as they are.

Mr. UPTON. And how fast would that have to occur?

Mr. EARLEY. That would have to happen over the next 4 years. There would not be enough time to build new capacity to replace it, given the time table of this bill.

Mr. UPTON. So we would have to purchase power from somebody else?

Mr. EARLEY. We would be forced to purchase power on the open market.

Mr. UPTON. And how easy is that to do?

Mr. EARLEY. Well, if the power is available, it is easy to do. What will happen is it will drive the price of electricity on the market. The laws of supply and demand can't be repealed, and we will be paying more and our customers will be paying more for electricity.

Mr. UPTON. And how much more do you think that would be?

Mr. EARLEY. Our estimate is that the overall cost to our customers is in the range of 25 percent increase if these regulations are implemented.

Mr. UPTON. So as we come from Michigan where we are already getting pounded with higher unemployment, this would add to those costs in a pretty dramatic way?

Mr. EARLEY. Absolutely, Mr. Chairman, and remember, it is on top of environmental controls that we already have installed that our customers are paying for, and the multiple regulations that are in the pipeline which will add to these costs. So it will be a significant burden for our customers that are challenged and are struggling to recover from the Great Recession.

Mr. UPTON. Mr. Fanning, is that about the same case for Southern Company, too?

Mr. FANNING. Yes, sir, we estimate the economic impact would be an increase in prices of about 25 percent for the southeast, and it would impair reliability potentially, which hurts economic growth.

Mr. UPTON. Mr. Papadopoulos, some of us suggest to clean it up, some of us would say these regs come in, we will move them out. Where is your competition for cement? What—who—what other countries compete, Mexico and China? Are they your prime competition?

Mr. PAPADOPOULOS. Back when we had——

Mr. UPTON. I don't know if your mic button is on.

Mr. PAPADOPOULOS [continuing]. When we had a very strong construction industry, let us say in 2005, the U.S. was importing about one-third of its cement needs, and the countries it was coming from, Asia was a big importer, China, Thailand, Korea, countries in Latin America, Mexico——

Mr. UPTON. What type of regulations do they have on producers of cement in Mexico and China?

Mr. PAPADOPOULOS. Well, they are moving but they are decades behind us.

Mr. UPTON. Decades behind us.

Mr. PAPADOPOULOS. Decades behind us.

Mr. UPTON. And what will the—if you kept all your production in the U.S., what will the additional costs be?

Mr. PAPADOPOULOS. Well, as we pointed out here through our study is to comply with just a couple of these—and we don't know if this is the end of the pipeline. This is a big uncertainty in our industry and probably other industries. It is going to take $5.5 billion, 85 percent of our annual sales. It is, on the other hand, not even going to help our costs. It is actually going to increase our costs by 20 percent, making us even less competitive with imports from overseas.

Mr. UPTON. Mr. Fanning, could you walk me through the "Frankenplant" exercise that you cited in your testimony?

Mr. FANNING. I am sorry, could you state it again?

Mr. UPTON. The "Frankenplant"?

Mr. FANNING. Oh, yes, sir. So a lot of the design characteristics that would follow the implementation of a MACT for different kids of emissions are designed to provide a MACT for one and then another and then another. It does not take into account the consolidated impact of all the emissions and therefore a single design.

What they would do is pull together the maximum available control technologies for each different design, and therefore create a plant, frankly, that may not be workable. That is why we use the phrase "Frankenplant".

Mr. UPTON. Mr. Kempf, I confess I am a Michigan man.

Mr. KEMPF. That is OK.

Mr. UPTON. I will be in South Bend tomorrow. That is where my plane comes in. I vote for the Irish in a lot of different ways. Great university. We have a very good rivalry, as you know, and as I visit some of my universities, Western Michigan University as an example, I visited their power plant.

So you have spent $20 million on your facility in the last 10 years?

Mr. KEMPF. Correct, that was our activity to achieve the original MACT that was promulgated.

Mr. UPTON. And it does not comply with these regs?

Mr. KEMPF. Well, the equipment that we purchased, obviously we sought a margin of compliance below the limit so we are in the '04 rule, but the new limits that are proposed are below the guarantees that we achieved from the manufacturers of the equipment.

Mr. UPTON. Thank you, and my time is expired.

Mr. WHITFIELD. Gentleman's time is expired. Chair now recognized Chairman Emeritus Waxman for 5 minutes.

Mr. WAXMAN. Thank you, Mr. Chairman.

There was testimony, Mr. Fanning told us that "The major flaw in EPA's analysis is that it makes overly optimistic assumptions about the effectiveness and availability of certain control technologies," specifically, dry sorbent injection, or DSI. Mr. Earley's testimony stated that EPA makes its determination about DSI based on one 3-week trial. Mr. Bradley, what can you tell us about DSI?

Mr. BRADLEY. I can tell you that I am not exactly sure how EPA judged its estimate on DSI. I can also tell you that in the NEDS database, you can look and see that dozens of units have been retrofitted with direct sorbent injection. These typically are smaller units, but it is a key component to achieving compliance with the standards.

Mr. WAXMAN. So it is already in use?

Mr. BRADLEY. Absolutely.

Mr. WAXMAN. I see. It is my understanding that the industry's cost assumptions and projected retirements depend on DSI not being available as EPA projects. Could you elaborate? Is that——

Mr. BRADLEY. Certainly. I think there have been a variety of analyses looking at this situation, prior to EPA proposing the rule. Now that the rule is out and the standards are set, and the standards are not as aggressive as I anticipated—this is for mercury, for PM and for acid gases—and they introduced quite a bit of flexibility that I think a lot of folks in the industry didn't anticipate. When you take all that into account, I think you are going to see the costs are going to be lower than what has been projected, and certainly the retirements will be less.

I think it is important to recognize that NERC looked at retirements prior to EPA's rule coming out, and their projection is in the range of 15 gigawatts. If you look at EPA's estimate plus what they saw happening naturally due to economic drivers like low gas prices, they are pretty much in the same range. But you know, it probably is going to be on the lower side of the ranges that have been proposed previous to the rule.

Mr. WAXMAN. Well, Southern Company disagrees with you. Now that we have heard from Southern on this topic before today, in 2004, Southern weighed in on EPA's first attempt to reduce mercury from power plants. They said that mercury control technologies were not commercially available and that the industry couldn't meet standards based on such controls. In fact, Southern official Larry Monroe stated, and I want to quote him, "With straining to do it, it is in the 2015 to 2018 timeframe that industry can get there." Three years later, without any EPA requirements to use mercury specific control technology, it was already in use on 11 units. Today, almost 100 units are using the technology. These standards could and should have been adopted years ago, and if industry hadn't said the cleanup couldn't be done, we would have already done it.

Mr. Walke, can you explain how these rules have been delayed? Why have we seen delay after delay?

Mr. WALKE. Yes, Congressman Waxman. The rules were delayed in the 1990s due to lateness in carrying out steps that Congress had demanded in the 1990 amendments to report to you all about the dangers of toxic pollution from power plants. But then EPA Administrator Browner in 2000 made a finding that should have required those standards to be adopted—to go into effect about 4 years later. Instead, the Bush administration did a total U-turn and adopted a rule that was struck down in 2008, consuming the entire 8 years of its two terms, preventing any regulation of arsenic, lead, and the rest from power plants. In fact——

Mr. WAXMAN. Rather than get going and getting this accomplished, we saw delays. Industry pushed for delays.

Mr. WALKE. I have to say there was strong pressure from some of my co-panelists to prevent EPA from adopting those regulations, and the Bush administration succumbed to that pressure and decided to do that.

Mr. WAXMAN. And the courts rejected their arguments.

Mr. WALKE. Not only did a court with Republican and Democratic appointees reject the arguments, but in fact they quoted Lewis Carroll's Alice in Wonderland for the absurdity of the legal argument that the Bush EPA had relied upon in unanimously rejecting that rule.

Mr. WAXMAN. Well, at last EPA's proposed a defensible standard. It is consistent with the Clean Air Act. It would save thousands of lives, prevent brain damage in untold numbers of children. I don't think we should be shocked to see the industry here today asking for as long as 10 years delay. These rules have been delayed long enough and industry has had plenty of notice. We must not deny our children these protections any longer.

Thank you, Mr. Chairman.

Mr. WHITFIELD. The gentleman from Texas, Mr. Barton, is recognized for 5 minutes.

Mr. BARTON. Thank you, Mr. Chairman.

Let me say it at the beginning that I will stipulate that mercury is a poison and a pollutant and SO_2 is a pollutant and these new standards, if adopted, would reduce those pollutants. I will stipulate that.

Having said that, it is a puzzlement to me that if you look at the indices for air quality in the United States, according to the criteria of pollutants that are covered under the Air Quality Act, our air quality is improving almost everywhere in the country. In the areas it is not, it is primarily places like Southern California where you have just a tremendous number of people and huge number of mobile sources and a geography that traps the pollution from tailpipes, and it is just very, very difficult to clean that up.

So you know, if you look at the facts and then you look at these proposed standards, I will even stipulate that they will make the improvement in the pollution control. The question is, Is it worth the cost? And if you want to know what the cost is, just look at what happened at the TVA yesterday. TVA announced a settlement with EPA that is going to close 18 of their coal boilers, close one of their coal-fired power plants, reduce the amount of electricity capacity by 16 percent. They also agreed to spend an additional $5 billion in the next few years on the plants they are not closing and the boilers they are not closing.

If we adopt these standards, that is what you are going to see across America. The other plants are just going to close because it just doesn't make sense to spend the money, and you don't get the environmental—I stipulate you get the cleanup in terms of lowering emissions, but there is not a real health benefit.

Now I want to apologize to you, Mr. Wade—Walke—Wade——

Mr. WALKE. Walke, Congressman.

Mr. BARTON. Walke, I am sorry. I am not being facetious.

Mr. WALKE. No, sir.

Mr. BARTON. We tried to get the EPA here and they wouldn't come, so you are the next best thing, OK?

Mr. WALKE. I am not sure how I feel about that, Congressman Barton, but——

Mr. BARTON. It is not personal, I assure you.

Mr. WALKE. I will not take it personal.

Mr. BARTON. But you were saying——

Mr. RUSH. Will the gentleman yield just for a moment?

Mr. BARTON. Very briefly.

Mr. RUSH. I see the gentleman refer to we tried to get the EPA to come. I just think that that is consistent with what we have been experiencing in the last couple months. We have given the EPA proper notice, and I know they have got a lot of employees over there, but they have very few employees who have this kind of expertise and who are supervisors who—that is the reason why Chairman Waxman and I——

Mr. BARTON. They have had since November, the first Tuesday in November to get ready, Mr. Rush, and we have had a number of hearings. I would encourage you to encourage them to show up so we don't have to——

Mr. RUSH. With all due respect to the emeritus and the Members on our side, we sometimes—we don't get notice until the last minute, so we have to scramble and we are here in the same building and operating in very close contact with you, and we have to——

Mr. BARTON. Reclaiming the time, and I would ask unanimous consent for 3 additional minutes, or at least 2. I don't know how long Mr. Rush took, but I have some pretty important questions I would like to ask.

Mr. RUSH. I have no objection.

Mr. WHITFIELD. Without objection.

Mr. BARTON. OK. Now let us go back to you, Mr. Walke.

In your testimony, you say that these standards would save 17,000 lives in terms of premature deaths a year, I think. Is that not correct?

Mr. WALKE. That is taken from EPA's projecting that up to 17,000.

Mr. BARTON. You stipulate it is a number you got from somewhere else?

Mr. WALKE. Yes, sir.

Mr. BARTON. I want to ask every private sector individual here, I will start with Mr. Fanning. How many cases in your company were there last year of mercury poisoning reported?

Mr. FANNING. None that I know of.

Mr. BARTON. Does anybody know of any mercury poisoning because of emissions from any of your plants? Do you know how many there were in the country last year? Zero. What about SO_2, any of you have any history in your plants of SO_2 poisoning? We cut SO_2 emissions by 50 percent in the last decade, and this, if implemented, cuts it another 50 percent but takes it from four million tons a year annually to two million.

Now Mr. Walke, again, it is not your statistic, but it is reported all the time. There is absolutely nothing to back it up.

Mr. WALKE. Congressman Barton, let me——

Mr. BARTON. Do you know how many—let me ask you. How many pounds of mercury is omitted from an average 500 megawatt coal plant a year?

Mr. WALKE. Congressman Barton, those are attributed to deadly soot pollution——

Mr. BARTON. Do you know the number?

Mr. WALKE [continuing]. Not mercury, so I want to be clear on the basis for my claim. It is particulate matter that kills people. EPA is not claiming——

Mr. BARTON. All right, then let us see that backed up.

Mr. WALKE. OK, I would be happy to, and that is a great thing for this committee to convene a hearing on with the National Academy of Science——

Mr. BARTON. Every 500 megawatt coal-fired power plant produces 3 pounds of mercury a year, 3 pounds. According to Mr. Walke's testimony, these standards reduce that 91 percent. Well, that is great. So you go from 3 pounds a year per plant to .3 pounds per plant, but that is per year.

Now to actually cause poisoning or a premature death, you have to get a large concentration of mercury into the body. I am not a medical doctor, but my hypothesis is that is not going to happen. You are not going to get enough mercury exposure or SO_2 exposure or even particulate matter exposure. I think the EPA numbers are pulled out of the thin air, and I am going to ask that we send an official document to EPA. Let us back them up, because the entire premise for going forward with these standards is that you get such a tremendous ratio of benefits to cost because they claim, according to Mr. Walke's testimony, which he is an honest man and he has got it from somewhere, is $140 billion annually. But if you really don't have the benefit because you are not having the medical negative, but you really have the cost—and if you don't think the costs are real, just look at how many factories are closing and going to Mexico and China. Look at the population of Mr. Dingell's home city, Detroit, Michigan. It has fallen by 40 percent, I think, in the last 20 years. If you don't think those are real—so if we are going to have a real debate about these standards, Mr. Chairman, we need to start getting some real numbers from the EPA and getting the EPA up here—if it takes Mr. Rush's help, Mr. Dingell, Mr. Waxman's, because if their benefits are not real and the costs are real, we are absolutely wrong to force these standards.

And with that, I have overextended even my extended time, and I yield back.

Mr. WHITFIELD. Well thank you. I might mention to the gentleman that there was an article in University of Michigan Law Review recently not too long ago that was quite critical of the method used by EPA in calculating health benefits.

Mr. BARTON. That is why we need the EPA here.

Mr. WHITFIELD. At this time I recognize the gentleman from Michigan, Mr. Dingell, for 5 minutes.

Mr. DINGELL. Mr. Chairman, I thank you and I thank you for your courtesy in yielding to me earlier. I would like to welcome my old friend Mr.—constituent friend. He heads a very fine public spirited company and I would like to ask him this question. Is there a difference between what DTE has been able to do at several power plants in my district? I know that you have been making significant investments as you referenced in your testimony to upgrade the environmental performance of these facilities, and I know that there are some problems in what is being contemplated under the proposed rules. Is that a correct statement?

Mr. EARLEY. That is correct.

Mr. DINGELL. All right. Now tell us what the differences are between EPA and DTE, and what it is they are requiring you to do and what it is you believe would be in the best economic interest of the company, and if it will repair industry jobs in Michigan.

Mr. EARLEY. Well, Mr. Chairman, the prior Clean Air Act amendments of 1990 gave us tremendous flexibility in terms about timing and the ability to sequence adding equipment by the ability to go out and buy allowances on the market. So as you know, we have spent several billion dollars at our Monroe power plant, but we didn't have to build all of the equipment at once. We were able to phase it in over time.

This rule will require every single unit on our plant to comply by a specific date. That will drive the costs up and it will force us, in many cases, up to 25 percent of our coal-fired power plants will have to be shut down because it will just not be economic.

The other point that I know you are aware of, we talk about imposing these requirements on utilities, we are imposing on our customers. For a utility, this is an opportunity for investment. Economically, we are not hurt by it as a regulated utility, but our customers——

Mr. DINGELL. What you are telling us they are forcing you to make investments that are not in the best interest of your customers for a momentary gain which, if you could go forward with your regular construction plans and improvement plans you would not make and you would serve better your customers and produce just as much clean air, but at a much lower energy cost and at a much lower emission of CO2? Is that right?

Mr. EARLEY. That is absolutely correct.

Mr. DINGELL. Very good. I would like to have you submit a bit more on that answer so that we have that in the record.

Now if—let us see. As I understand, then, that there are several older electrical generating facilities that are scheduled to be shuttered in the next decade, and as you have indicated, that that shuttering will be hurried up and you will be compelled essentially to move instead of to nuclear, which you are contemplating doing, moving to natural gas combined cycle generating systems. Is that right?

Mr. EARLEY. Yes, sir.

Mr. DINGELL. And that constitutes a complete change in the investment plans that you have in the company, is that right?

Mr. EARLEY. Yes, sir.

Mr. DINGELL. Very good. Now, these questions for Mr. Walke and Mr. Krouskop. It is my understand that EPA requested additional time for the rule. Is that right?

Mr. KROUSKOP. For the boilers rule, yes, sir.

Mr. DINGELL. All right, and you agree with that statement, Mr. Earley?

Mr. EARLEY. Yes.

Mr. DINGELL. Has industry filed a motion for a stay on the Boiler MACT?

Mr. KROUSKOP. We are continuing to work both from the perspective with EPA for reconsideration, requesting a stay, and also are considering from a judicial standpoint what are options are for requesting a stay.

Mr. DINGELL. I have been hearing that this would be a good solution to the problem, that EPA would not oppose that kind of step and that that would help us resolve the problem that lies before us. Am I correct in that?

Mr. KROUSKOP. I think that it is generally correct. I think EPA certainly indicated they needed quite considerable additional time to get the rule right. At the same time, though, there are some elements of the Boiler MACT rule which EPA has been resistant to correcting the way we believe they are, and that really is around the health-based compliance alternative, which is part of the Clean Air Act, and we believe that is appropriate.

Mr. DINGELL. Thank you. I have got 9 seconds to ask this question, Mr. Earley. So we can say here, Mr. Earley, as a result of your testimony that the requirements of Utility MACT go beyond your facilities and your jobs. In other words, there is a potential for impacts to go well beyond the electrical generating sector and to compel you to make business decisions that may be well beyond and well different than what you had made that may not be either in the interest of your consumers or in the interest of the public and might very well result in wasteful use of energy, and of capital. Is that a correct statement?

Mr. EARLEY. That is correct, Chairman.

Mr. DINGELL. Thank you, and I thank you, Mr. Chairman.

Mr. WHITFIELD. At this time I recognize the gentleman from Illinois, Mr. Shimkus for 5 minutes.

Mr. SHIMKUS. I thank you, Mr. Chairman. I am going to go quickly, too, to get through my questions. We wanted the EPA back here again. We had them here yesterday in coal combustion waste. There's a President Executive Order that says all the new regulations have to comply with an economic analysis. What we found out yesterday in the hearing is just even though EPA does an economic analysis, they don't translate to that job impact. So if there is an economic analysis there is going to be a job impact, so we welcome EPA to hopefully coincide with the President Executive Order doing an economic and a job analysis, because that is what this is about, complying without destroying jobs.

First thing, Mr. Bradley, have you ever designed a power plant?

Mr. BRADLEY. Have I ever denied?

Mr. SHIMKUS. Designed.

Mr. BRADLEY. Designed, no.

Mr. SHIMKUS. Sited?

Mr. BRADLEY. No.

Mr. SHIMKUS. Built?

Mr. BRADLEY. No.

Mr. SHIMKUS. Raised capital to build one?

Mr. BRADLEY. No.

Mr. SHIMKUS. Conducted a payroll for the power plant?

Mr. BRADLEY. No.

Mr. SHIMKUS. Provided healthcare benefits for the employees?

Mr. BRADLEY. No.

Mr. SHIMKUS. OK, thank you. In your written testimony on page 4, you state that Constellation recently installed a major air quality control system at its Brandon Shore facility, and that construction was completed in 26 months. Now time is one part of this debate, it is a key issue in implementation. Is that an estimate? That construction took a little over 2 years, is that accurate?

Mr. BRADLEY. The construction itself took 26 months.

Mr. SHIMKUS. And I would turn to and ask for unanimous consent to put into the record an article that states that that construction was at least a 3-year construction. So I would ask you to relook at that, because I don't think that is correct in your testimony.

[The information follows:]

March 1, 2010

State-of-the-Art Emissions Scrubbers at Constellation Energy's Brandon Shores Power Plant Commence Commercial Operation

BALTIMORE, Mar 01, 2010 (BUSINESS WIRE) -- Constellation Energy (NYSE: CEG) today announced that its flue gas desulfurization or "scrubber" project at its Brandon Shores Power Plant in Anne Arundel County, Md., has begun commercial operation, making Brandon Shores one of the cleanest-burning power plants of its kind in the nation.

This nearly $1 billion investment is one component of a clean air program which will ensure Constellation Energy's coal-fired power plants will meet all emissions requirements of Maryland's Healthy Air Act, which was signed into law in 2006. Constellation Energy's investment in this environmental upgrade will reduce the coal-fired power plant's sulfur dioxide (SO_2) emissions by an estimated 95 percent and existing mercury emissions by 90 percent.

"Constellation Energy has a long and demonstrated commitment to environmental stewardship throughout the communities in which we live, work and do business," said Mayo A. Shattuck III, chairman, president and chief executive officer of Constellation Energy. "Over the past decade, we've made a number of major environmental investments and improvements at our generating facilities, and the Brandon Shores scrubber project represents one of the most notable steps in our environmental stewardship efforts. The completion of this project illustrates our commitment to investing in the latest clean air and environmental technology as part of a broad and ongoing effort to make our generating facilities as environmentally friendly and sustainable as possible."

Scrubbers work by spraying a mixture of limestone and water into gases created during the coal combustion process. As sulfur dioxide in the gases comes in contact with the mixture, it is absorbed and neutralized by the limestone to produce gypsum, a useful additive to concrete or for the production of wallboard. The scrubber project also resulted in the construction of a new emissions stack that produces a visible plume of harmless water vapor emitted as part of the "scrubbing" process. The two existing larger emissions stacks at the Brandon Shores plant have been sealed and capped off and taken out of service but will remain in place.

Constellation Energy's clean air program includes several additional environmental upgrades at the Brandon Shores plant, including the installation of baghouses to remove particulates, as well as sorbent injection technology, which removes mercury and sulfuric acid mist from the plant's emissions. Constellation Energy also previously installed a selective catalytic reduction system at Brandon Shores, which significantly lowers nitrogen oxide emissions.

Even with scrubber technology, Brandon Shores, as all coal power plants, will still produce carbon dioxide, a greenhouse gas. Constellation Energy strongly supports actions and policies to address these emissions, including new laws and incentives, energy efficiency, and new investment in the cleanest of energy technologies such as nuclear, wind and solar.

Construction on the scrubber project took three years to complete and included nearly four million man-hours of work from representatives of the Baltimore Building and Construction Trades Council.

About Constellation Energy

Constellation Energy (www.constellation.com) is a leading supplier of energy products and services to wholesale and retail electric and natural gas customers. It owns a diversified fleet of generating units located in the United States and Canada, totaling approximately 7,100 megawatts of generating capacity, and is among the leaders pursuing the development of new nuclear plants in the United States. The company delivers electricity and natural gas through the Baltimore Gas and Electric Company (BGE), its regulated utility in Central Maryland. A FORTUNE 500 company headquartered in Baltimore, Constellation Energy had revenues of $15.6 billion in 2009.

SOURCE: Constellation Energy

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Mr. BRADLEY. I can provide you with more——

Mr. SHIMKUS. I would be happy to see whatever documentation you have. The company says it was a 3-year construction, so they dispute your opening statement.

Mr. Fanning and Mr. Earley, what happens if there is a race to build in this 3-year timeframe on cost of equipment, metal, employees? What happens to the overall cost of these projects?

Mr. FANNING. Well, they go up dramatically.

Mr. SHIMKUS. Dramatically, three-fold, four-fold?

Mr. FANNING. Sure.

Mr. SHIMKUS. And what happens to the cost to the consumer? What are you going to have to do?

Mr. FANNING. Raise prices.

Mr. SHIMKUS. Does anyone dispute that? Mr. Earley, do you dispute that?

Mr. EARLEY. No, I agree with Mr. Fanning on that.

Mr. SHIMKUS. OK, let me go to Mr. Kempf. I, too, have great respect for the institution of Notre Dame. I am a Missouri Lutheran. Hopefully I try to be devout—I am being serious here.

In your opening statement, you say that the EPA has not justified by corresponding environmental health protections from reduction of hazardous air pollutants. So you are staking Notre Dame's institutional position and it is very similar to the comments by the Chairman Emeritus Barton on the whole mercury debate, that 2 pounds versus .2 pounds, there is no mercury poisoning reported last year. Aren't you staking the university's position that there—these have, as you say, is not justified by corresponding environment and health protection from reduction of hazardous air pollutants?

Mr. KEMPF. I don't know that I am the person who can make that statement for the whole institution. I think our concern is that we want to make sure that——

Mr. SHIMKUS. But you are making it for this—in this testimony today——

Mr. KEMPF. Correct.

Mr. SHIMKUS [continuing]. As the director of utilities.

Mr. KEMPF. We are looking for a fair and balanced regulation that we can achieve at a reasonable cost.

Mr. SHIMKUS. And I think that is part of this debate. Cost benefit analysis, again, we welcome EPA to justify the loss of jobs for negligible toxic emittent benefits. Negligible, zero. Now, we could talk with Mr. Walke on particulate matter, but we are using particulate matter to address toxicity. EPA is not addressing toxicity. All this debate is on PM.

Mr. Walke, I don't want to go down this route, but you raised it in your opening statement. You are concerned about mercury contamination in the unborn child, is that correct? That is part of your opening statement?

Mr. WALKE. That was.

Mr. SHIMKUS. Does the NRDC have a position on abortion?

Mr. WALKE. Not to my knowledge.

Mr. SHIMKUS. And you know that is the destruction of—I will use the pro-choice vocabulary—that is a fetus, right? An unborn child is a fetus. You are concerned about the fetus and mercury poisoning, but NRDC doesn't have a position on the protection of a fetus on abortion? Is there a conflict here between life and health?

Mr. WALKE. I don't think there is a conflict, but——

Mr. SHIMKUS. I think there is a huge conflict, and I would——

Mr. WALKE. Fetus—neurotoxicity by mercury poisoning——

Mr. SHIMKUS. I would say that if NRDC is concerned about mercury poisoning, then they ought to be concerned about the destruction of human life in the process of abortion.

I yield back my time.

Mr. WHITFIELD. Thank you. Mr. Gonzalez, you are recognized for 5 minutes.

Mr. GONZALEZ. Thank you very much, Mr. Chairman. I have 5 minutes, and we have so many witnesses so I am going to employ the John Dingell method, and that is just a yes or no answer. We will start with Mr. Fanning. Do you believe that the Clean Air Act should be repealed? I mean, let us just forget about it. Let us just go straight to it. Is it relevant? Do we need it? Should it be repealed? Yes or no.

Mr. FANNING. No.

Mr. EARLEY. No.

Mr. BRADLEY. No.

Mr. KEMPF. No.

Mr. WALKE. No.

Mr. KROUSKOP. No.

Mr. PAPADOPOULOS. If repeal means upgrading it, yes.

Mr. GONZALEZ. Are you for repealing it, just repealing it?

Mr. PAPADOPOULOS. The Act is functional.

Mr. GONZALEZ. See, you are an interested witness and I am leading you, so it is a yes or no answer.

Mr. PAPADOPOULOS. I am sure going to, thank you.

Mr. GONZALEZ. Are you for repealing the Clean Air Act?

Mr. PAPADOPOULOS. I am for replacing it with something more——

Mr. GONZALEZ. OK, you are for repealing, then you—that is good. That is an honest answer. You are for repealing the Clean Air Act. Now I am assuming that you said that—those that answered no, is that it is still relevant and that EPA has the responsibility to protect the public's health, and this is one way of doing it. Should we disregard a rule that is promulgated by EPA, simply based on the fact that it does add some cost to protect the public's health? Yes or no, and we will start with Mr. Fanning.

Mr. FANNING. You can't disregard it, but it needs to be modified. The rule as proposed doesn't work from a timing standpoint, first to understand what is in the rule, and secondly to comply.

Mr. GONZALEZ. I am actually going to get into that. I just want general propositions so that we can maybe agree on some things here.

Mr. EARLEY. I think as a general proposition as in cost alone wouldn't justify, but there has to be benefits that are consistent with the costs.

Mr. GONZALEZ. Mr. Bradley?

Mr. BRADLEY. I agree with my colleague.

Mr. KEMPF. I would agree that, you know, that we should be expecting costs, and that is acceptable.

Mr. GONZALEZ. Mr. Walke?

Mr. WALKE. My answer is no, it is worth spending money to protect children and to save lives.

Mr. KROUSKOP. Rules have to be achievable and affordable.

Mr. PAPADOPOULOS. Cost is essential.

Mr. GONZALEZ. Yes or no, does the EPA have the expertise presently to be able to promulgate rules that get the science right, the technology right, and the cost right? Yes or no?

Mr. FANNING. I think they need to involve history—I mean, industry. They can't do it by themselves.

Mr. EARLEY. Alone they don't have all the expertise.

Mr. BRADLEY. Yes, they have the expertise.

Mr. KEMPF. Not in a vacuum.

Mr. WALKE. Yes.

Mr. KROUSKOP. Alone they don't have the expertise.

Mr. PAPADOPOULOS. A very strong no.

Mr. GONZALEZ. All right. You expect us as Members of Congress to basically listen to one side or the other's experts. It has been my experience it just depends who the expert is basically representing at that point, because they are defending their opinions. Should we just be listening to industry's experts or just EPA's experts? How do we determine which is a legitimate source of good, solid information? Because I am going to tell you right now, we will argue up here over whether there is climate change taking place and we will even argue over evolution. So good luck. Who do we listen to, industry or EPA? Whose experts? Should we have some other referee other than Congress? And I am not trying to shirk our duty, I am just telling you the stuff that you present to us is really many times incomprehensible because we are not experts, and we expect that experts from industry and experts from EPA are going to give us an honest opinion, but you guys don't agree, so who do we listen to? I only have 30 seconds. Tell me who should we have as the disinterested third-party expert?

Mr. FANNING. Congressman, I think you are making a great point that—for the need to review this rule and debate with EPA its ramifications in a reasonable timeframe. I think that is why we need more than 60 days in order to really understand 1,000 pages of a proposed rule and 1,000 pages of documentation underlying it.

Mr. GONZALEZ. Mr. Fanning, my time is up, and to the other witnesses, if you could supply that answer. You tell me who that referee, that disinterested third-party expert—I am not adverse to extensions of time to get people that are impacted time to comply and understand and evaluate, but when we do that, I also want to know that you just won't be asking for more time.

Thank you very much, and I yield back.

Mr. WHITFIELD. The gentleman from Oregon is recognized for 5 minutes.

Mr. WALDEN. Mr. Chairman, first of all thank you for holding these hearings on these rules. I was kind of amazed the other day when we had one of these hearings to hear I believe it was a witness from the EPA talking about the job creation that is going to come from all of these regulations. Having been a small business owner for over 20 years, I am always astounded when the government puts on a rule that is very expensive and calls that job creation. They don't look at the other side of the equation. In my district, Mr. Papadopoulos, we have a cement plant that Ashgrove, I believe, owns. They have invested $20 million installing and activating a carbon injection system. They have optimized their ACI to achieve 95 percent reductions in emissions, and EPA wants them to go to 98.5 percent, and the rule requires them to sustain those reductions over a 30-day average. So even if you have a little blip, you are out of compliance. There are 116 jobs on the line, most of them union. This is Baker County's largest single taxpayer and employer, and puts $9 million into the economy.

Now I know some of my colleagues on the other side of the aisle say oh, that doesn't matter because they are not really for jobs in the private sector anyway, some days, I believe. This is going to devastate the economy and the economy of the rural eastern Oregon county I represent. The difference between 95 percent and 98.5 percent is the equivalent of less than a teaspoon of mercury a day. Over that, we probably are going to lose this plant and those manufacturing jobs, and will end up importing more cement from China.

So Mr. Papadopoulos, do you believe the EPA should exercise its authority to use the flexibility provided in the Clean Air Act amendments of 1990, flexibility that issued sub-categories?

Mr. PAPADOPOULOS. I think this is a very important question——

Mr. WALDEN. Please turn on your mic there, sir.

Mr. PAPADOPOULOS [continuing]. For our industry, because we are different from power generation and other industries in that we depend on the raw materials that exist there on the site, what Mother Nature has provided the cement plants. These raw materials come in perfect, and therefore there is a whole wide range of outcomes when you use those raw materials. It would make absolute sense for the EPA to say let us look at the specific environment in which categories the plants are, and let us work with industry.

I think to answer some of the questions, we need a win/win collaboration with government——

Mr. WALDEN. Right.

Mr. PAPADOPOULOS [continuing]. Not a win/lose litigation, fighting heavy-handed, you know——

Mr. WALDEN. Job killing. Can I throw in job killing in that process?

Mr. PAPADOPOULOS. Job killing. Germany has done that. The reason—because I worked internationally, the reason Germany today is the global powerhouse along with China is because Germany has a win/win attitude working between government and industry. We need to bring that process back here to the U.S. This is a prime example of a company actually doing the right thing and in the end, getting penalized.

Mr. WALDEN. And by the way, they met the requirements, I am led to understand, that the State of Oregon had put in place prior to these new requirements coming out from the EPA. And then the State wouldn't even back them up with the EPA. It was really, really quite frustrating and remains so.

I got to tell you, I represent a district where I have got counties that have been averaging 15 and 16 percent unemployment for way too long. We have 55 percent of the land out there is owned by the Federal Government and mismanaged or not managed at all. There are groups, some of them represented at this table, who could care less about the livelihood of the men and women who live out in these forested communities who are fighting us on biomass, turning wooded biomass into productive, renewable energy. They would rather let the forest get overstocked, bug infested, rot and die, and then catch fire and burn. They wouldn't let us go in. They go in and sue us to go in and cut the burn dead trees while they still have value. These are not environmentalists. I don't know what they are, but they are sure destroying my part of the world and the economy there.

We can find good partnerships. My State has led the way in environmental activism in a positive way, in most cases. I am going to tell you, these new federal rules are shutting down everything that matters out there in my part of the world. The new particulate rules on dust—how about in eastern Oregon? I mean, we grow they'd probably have to drag a mister behind their machinery in order to hold the dust down. We wouldn't call it dry land farming if we had that much water. This administration is killing more jobs in rural communities than prior administrations combined. This President doesn't understand what his own folks are doing. I have about had it, and so have the people I represent.

So we are going to go after this agency. We are going to bring some damn common sense to the process and these groups that are killing the folks out there, they need to have some skin in the game and not just use these things as big fundraising efforts, which is what generally happens. There is common sense here. We can get America working again. We can get back on our feet out there, if you will just let us.

Mr. WHITFIELD. Thank you, Mr. Walden. At this time, the gentleman from Texas, Mr. Green, is recognized for 5 minutes.

Mr. GREEN. Thank you, Mr. Chairman.

Mr. Fanning, Mr. Bradley testified that the installation of control technology can occur in 26 months. Southern has found that scrubbers average 54 months to install. Can you explain the apparent discrepancy?

Mr. FANNING. I would be glad to, thank you. In fact, it is interesting to look at the actual permit application for the constellation scrubber that they refer to. When they made the application, they sought approval for the scrubber and cited a 41- to 46-month installation schedule. I think the confusion probably arises from the fact that when you consider adding new equipment, you have got to go through the whole process of design, permit, and then build. I think the confusion in the 26-month reference only relates to when you start to break down and actually build the plant. When you put in new facilities, you need to take into account the design characteristics of the unit in question, the permits that need to be applied for and received, and then ultimately specific site engineering and construction.

Mr. GREEN. What is the lag time on the permits? Once you get the permit in there, how long does it take to get a permit?

Mr. FANNING. Well, that is certainly, you know, matters on State to State, because these are generally State issues at that point.

Mr. GREEN. Do you have an average?

Mr. FANNING. Round numbers, I don't know, 12 to 18 months.

Mr. GREEN. OK, so anywhere from a year to a year and a half?

Mr. EARLEY. We think 18 months is probably a working number.

Mr. GREEN. Thank you. This is a question for Mr. Fanning, Mr. Earley, and Mr. Bradley.

EPA estimates that 10 gigawatts of coal-fired power will retire rather than install controls. Can each of you state whether you agree with that conclusion?

Mr. EARLEY. We disagree with that conclusion. We think it is going to be a much larger number.

Mr. GREEN. Do you have any idea? I mean, I know we are just guessing, but——

Mr. EARLEY. Yes, I think it is going to be more in the range of 50 to 75.

Mr. FANNING. Yes, we think it is—70,000 to 80,000 is what we think, and the answer is really pretty simple. They believe dry sorbent injection is going to solve one problem, and it actually creates another. It creates a particulate matter problem that would need to be dealt with. It will not be a widespread solution.

Mr. GREEN. OK, Mr. Bradley?

Mr. BRADLEY. Yes, I think 10 gigawatts is on the low side. I think EPA targeted that specifically to the Utility Toxics Rule. I think they have acknowledged that more retirements will happen through just market pressures.

I think it is also important to go back and reassess the retirement issue based on the proposal itself and the flexibility that is included. The—certainly NERC is more on the ballpark with EPA, but I think it is going to be hard to project exactly what is driving retirements. Is it singly the Utility MACT rule or is it low natural gas prices, depression of demand, the inefficiency of some of these old plants?

Mr. GREEN. OK. This question, Mr. Fanning, in your testimony you say that "EPA goes to set limits separately for individual pollutants using different sets of best performing plants. EPA's resulting suite of emission limits does not reflect the performance of any existing plant, but instead reflects the performance of so-called 'Frankenplant,' one consisting of mixed-suite performance characteristics that do not represent the technology applications across all pollutants for that individual facility." Mr. Earley, do you agree with Mr. Fanning's statement?

Mr. EARLEY. I agree with that.

Mr. GREEN. OK. Mr. Bradley, you argue that the EPA proposal is based on standards performance that is already achieved by existing plants, so how do you respond to Mr. Fanning's statement about the "Frankenplant"?

Mr. BRADLEY. I would be happy to submit for the record a list of plants that are documented in EPA's database that are based on data that companies submitted, and there are 27 units and 16 plants in that database that—preliminary analysis of ours that represent both sub-bituminous, bituminous, and even one lignite plant that currently meet the standards.

Mr. GREEN. I would appreciate that. In my 26 seconds, Mr. Fanning, you talked about the delay—and I know there are other questions from other Members—can you specifically talk about how long do you think it would take to need to implement the rule? I know 30 days is too short, 60, what is the time? I know Congressman Gonzalez mentioned that.

Mr. FANNING. Yes, I would be glad to. We think there needs to be a thorough review process. Remember, this is the most expensive proposal put forth in a MACT form that EPA has ever done, 1,000 pages, 1,000 documentation. We need to go through this and really understand the science first, number one. So my view is we need some extension on evaluating what is being proposed, and I think one of the issues that we get to on all of this dry sorbent injection, all these other things, is the combined effect of the controls of all these plants. Further, we need to have a reasonable way to implement this requirement. Our company is already transitioning our coal fleet. We have examples of that I could tell you about, but in order to account for an orderly way to run your generation portfolio for the benefit of customers to ensure that you have reliability in a reasonable economic impact, and to assure that you have reasonable participation by vendors and required craft workers to undertake these billions of dollars of capital, my sense is you are going to need somewhere in the 6-year timeframe to get this done reasonably.

Mr. GREEN. OK. Thank you, Mr. Chairman.

Mr. WHITFIELD. Mr. Pompeo, you are recognized for 5 minutes.

Mr. POMPEO. Thank you, Mr. Chairman, and thank you all for coming here today.

You know, I have been here only 100 days, and when I look at something like this, it is staggering because we are talking about one set of rules today that you all are trying to deal with and create jobs and create energy. So manufacturing guys, like I was 101 days ago, I find it surprising that so many of you are still here working, banging away in the United States trying to create jobs. I admire you for continuing to do that and continuing to fight the fight to help us understand what it is that will allow you to do those things. I come here today, you all come here today, but the EPA chose not to. We have this constitutional oversight duty, and yet they don't come so we can hear the things that they want to tell us and present their side and their set of facts. It is incomprehensible to me that they are not here.

I heard the ranking Member say today that EPA had very few experts. I don't know about all that. What I can tell you when you look at something like this and they got too few people with common sense, I am confident of that.

Mr. Krouskop, you gave me the chart so I want to ask you just a couple questions. There was a piece in your testimony about the secondary materials rule and how that impacts your business. Can you tell me a little bit more about that?

Mr. KROUSKOP. Yes, the secondary materials rule is basically—Boiler MACT is actually four separate rulemakings, and one of them deals with the definition of solid waste. One of the areas that, of course, products industry is very interested, and quite frankly, I think from an energy perspective we are interested in creating renewable energy, and it certainly is questionable as to the way the rule is written is whether or not things like biomass would not be classified ultimately as a waste, which would then require even more expensive control systems to be put on those boilers.

Mr. POMPEO. I appreciate that. I want to come back to something, too, and I will ask everyone on the panel.

So there was this notion that there has been this delay, a decade, 12 years, 13 years, and that you all should have been doing something in that time. The notion was hey, you have had 15 years to get ready for this, but the truth is, if you would have taken action, much like your university did during this 15-year timeframe, I would like to ask you if you think you would all be looking at something that was going to cost you even more money? That is, you would have been trying to guess what EPA was going to do. I want to ask you if that is something that when you present to your employees and your regulated—the folks that regulate your utilities or your shareholders, if that is something that they would say hey, that is exciting, we want to go invest some money trying to guess what EPA is going to do. We can start down here with Mr. Fanning.

Mr. FANNING. I am proud to say we have already invested—committed to invest more than $10 billion on improving the climate. We are the leader in the industry in that respect, and we are going to invest more.

Mr. POMPEO. I hope you guessed right.

Mr. FANNING. Well, the other issue that is just very important that you are hitting on here is we are in the Southeast, which is largely an integrated regulated electric system. We have a constructive relationship with our regulators and we go through very disciplined processes to evaluate ultimately the impacts for our customers on reliability, price and environmental impact.

These are policies that have should be followed through and have served us well in the past, and will require more time than what is permitted in this proposal.

Mr. EARLEY. Congressman, we have done the same thing. We have invested well over $2 billion, but what this rule shows is we will have to invest even more, and as I say in my testimony, we have slashed emissions over the last 30 years, and it is a lot of great success stories. I think we have to use some common sense going forward. At some point enough is enough, and you just can't afford to spend the next dollar for another piece of equipment just because the equipment is available, because these costs are borne by our customers, your constituents.

Mr. POMPEO. Thanks to those who responded. You know, Kansas we have got a utility plant that has been trying to be built to retire some older, less clean technology, and our former governor, now the Secretary of HHS, didn't let them do it. So this was a company that was trying to invest, trying to create jobs, trying to create affordable energy, and was prevented by doing so by the Kansas Department of Health and Environment, and ultimately by EPA, too.

I have just got 20 seconds. Mr. Bradley, you think these make sense. I am trying to understand what is different about the businesses that are part of your group as opposed to the folks sitting to your right. Why is it that you think they make sense and they don't?

Mr. BRADLEY. These have been clearly on the books and on the horizon for more than 10 years. The companies I represent have a responsibility to their shareholders, to their customers, to their employees to plan ahead, to do risk assessment, and manage their investments, and they have made those investments in a way they are in a pretty good position——

Mr. POMPEO. You just—frankly, the folks you represent just have a lot different mix of energy. You have got a lot less coal involved in the folks that you represent than some of the other folks sitting on the panel.

Mr. BRADLEY. That is correct.

Mr. POMPEO. So this would be—these rules would be good for your folks because they would cause your profits to increase and the others——

Mr. BRADLEY. Yes, but let me emphasize that the number of my companies that I represent have invested the hundreds of millions of dollars to clean up their coal facilities as well.

Mr. POMPEO. Thank you. I yield back my time.

Mr. WHITFIELD. The gentleman Mr. Inslee is recognized for 5 minutes.

Mr. INSLEE. Thank you.

Mr. Fanning, I was interested in your technology, reading your written statement, you said "Second, we need a national robust research and development effort to create new energy technologies for the future," and I very much agree with that. Apparently so does President Obama. He said yesterday "I will not sacrifice the core investments we need to grow and create jobs. We will invest in medical research and clean energy technology."

Now, there are efforts here to reduce—not increase, but actually reduce our national investments in clean energy research. I think that is a huge mistake. It is like eating your seed corn. Would you urge us on a bipartisan basis to increase our federal investment in clean energy research across the board in all CO2, non-CO2, and low-CO2 emitting technologies?

Mr. FANNING. Absolutely. I am on record as saying that this should be a national imperative.

Mr. INSLEE. Well, I would hope you might spend some time with some of my Republican colleagues, talking to them about the importance of this investment and the potential job creation technology. I am serious about this. We have deficit challenges here that are very, very important, but as we make priority decisions, if you have a chance to talk to some of my colleagues about the job creation potential of that research, I think it could be beneficial. Thank you.

Mr. Walke, I have—I want to ask you to comment on something that I found fascinating. Mr. Earley talked about yearning for the good old days of a proposal to have something like a cap and trade system where we gave flexibility to industries to try to figure out what actions and what investments to take to clean up our skies. I am not liking this what you might call a command and control system that sets up regulatory systems about specific behavior. Now it seems to me a little bit ironic that one side of this aisle here rejected Congress doing something that would have given industry flexibility on how to decide where to make investments. Then when we take the alternative approach, which is a regulatory approach, rejecting that approach. Now that to me seems a little bit ironic. What do you think?

Mr. WALKE. Well, what they share in common is a desire to avoid reducing pollution in both cases, so there is that consistency, that failure to support carbon cap and trade legislation and failure to support the command and control programs. But EPA has flexibility, including averaging in this toxics rule, and there is a deep commitment to carrying out a law that was adopted by 401 Members of the House in 1990.

Mr. INSLEE. Thank you. Mr. Krouskop, if I can ask you a question. If you had in your broadly industry—three industries kind of associated with this rule, if these industries were taking some action that resulted in the premature deaths of 26,000 people a year in America, not China, in America, 26,000 Americans a year, and if your industry could make an investment that would return to the national economy at a minimum five times more benefits by eliminating those premature deaths for every dollar of investment, would you make that investment? Would you suggest that we as a community make that investment?

Mr. KROUSKOP. I think the real question here is how fast you make the investment and to what degree do you compare some of the benefits and the costs to those investments. I think that is what we are saying.

Mr. INSLEE. So let us start at the beginning of my question. If you could make an investment of $1 that could result in 26,000 deaths—premature deaths in the United States, and would return economic benefits of a minimum of $5 to the Nation, let us just start with that presumption. Would you suggest that the industry make that investment?

Mr. KROUSKOP. If you buy the premise of the dollars and there has been lots of discussions about, A, truly are those numbers correct, and are the estimates of health effects associated with these things, the answer, of course, is yes.

Mr. INSLEE. Well, I don't think it is of course, because I have heard at least five witnesses say and we say to ignore this cost benefit analysis. This is very problematic to me, and let me tell you why. The only comprehensive assessment of the cost benefit analysis is the one presented by the EPA. I don't see anything coming from industry that is really presented a contrary opinion. Now, that is problematic to us as a policymaker. Mr. Papadopoulos wants to say something. Go ahead.

Mr. PAPADOPOULOS. I want to say that, you know, statistics that have come out of computer models are one thing. Proof in the field, empirical proof is another thing. If I knew that even one person was——

Mr. INSLEE. Let me stop you just for—I only got 13 seconds.

Mr. PAPADOPOULOS. I would have gotten it tomorrow. I would wait for EPA to come.

Mr. INSLEE. I am waiting for something from you guys. I would like to see it.

Mr. WHITFIELD. The gentleman's time is expired. Recognize the gentleman from Virginia, Mr. Griffith, for 5 minutes.

Mr. GRIFFITH. Thank you, Mr. Chairman. If we could put up a map showing the percentage of mercury deposits from outside the United States, I believe the committee has that. Oh, there it is.

Mr. Papadopoulos, thank you for having a facility—I guess I should ask before I get to the map, when you talked about closing down older plants, I hope that doesn't include Roanoke Cement just outside of my district in Botetourt County.

Mr. PAPADOPOULOS. We are trying very hard.

Mr. GRIFFITH. I appreciate that. When you look at this map, it appears that a significant amount of mercury in the U.S. comes from outside the country. Now so you will know, the chart indicates the percentage of mercury deposits that are from outside the country, so the red would be 100 percent and down, and purple would mean that most of it is coming from this country. So it appears that a lot of the mercury is coming from outside the country. Can these foreign mercury emissions be reached by EPA regulations?

Mr. PAPADOPOULOS. None at all. They will worsen, in fact.

Mr. GRIFFITH. And isn't it accurate to think that if these mercury emissions—and I heard you say something about this in your opening statement, too, or at least get close to it, but isn't it a fact that if they are coming from outside the United States and we drive manufacturing—all kinds, but particularly in your case, the production of cement, to other countries like China, India, or Mexico, aren't we, in fact, increasing the likelihood or increasing the amount of mercury that may actually come into these United States?

Mr. PAPADOPOULOS. Exactly. The EPA has all these studies, but it refuses to communicate them, and you know, I heard a statistic from Mr. Waxman that I wanted to correct. He said that the cement industry is the number three producer of mercury in the U.S. That is incorrect. In fact, we rank number nine. The U.S., in fact, is one of the smallest mercury producers in the world. Compared to our energy footprint, our mercury production globally is only 7 percent, and 80 percent plus of the mercury that comes into the U.S. originates offshore. So unless we are planning to build a big glass globe around the country, we could shut everything down and still this won't change. It will get worse.

Mr. GRIFFITH. Thank you. I do want to shift over to my friends from MeadWestvaco. I asked staff when I saw the witness list today, I said did you all set up this hearing for me? My understanding is that Eastman was also invited, and they are on the other end of the district, just outside of the district. But if I could ask you a few questions, I do appreciate your facility there, and I am going to mispronounce your name. Help me with it.

Mr. KROUSKOP. Krouskop.

Mr. GRIFFITH. Krouskop. I do appreciate your facility there in Covington. Obviously you employ a lot of people, as does Mr. Papadopoulos, in the 9th Congressional District of Virginia, and both of you all have great companies.

But let me ask you, looking at Boiler MACT as well as other current EPA air regulations that are looming over the next several years, can you explain in general terms the investment and technology control issues that a mill like yours is facing with these regulations?

Mr. KROUSKOP. Yes, the investment, for example, for Covington Mill associated with these regulations certainly are in the tens of millions of dollars. I think the fundamental question here is as much about how do we effectively accomplish the goals of the Clean Air Act and the MACT rulemaking and control toxics and not have to spend so much money. We would submit that there is, in fact, technology to do that.

Mr. GRIFFITH. All right. Your testimony basically says the EPA and the Boiler MACT rule in its current form has essentially failed to capture what is the essence of what real world industrial boilers actually achieve. Can you elaborate on that?

Mr. KROUSKOP. Yes, one of the most difficult parts of the Boiler MACT rulemaking was, even though EPA did go to a sub-categorization system, in effect what they did rather than saying here is boiler X and it can achieve these things and we will look at the best 12 percent performing of all boilers, they literally cherry-picked pollutant by pollutant. So when you look at the true number of boilers that could achieve these rules today, they are much less than 10, based on our analysis, of about over 3,000 boilers nationwide.

Mr. GRIFFITH. All right. My time is just about up, but I just again want to say thank you to all of you. Anybody else who wants to bring jobs to the 9th District of Virginia, you are more than welcome. We understand that there has got to be a balance that you want to have clean air and you want to have clean water. The EPA has a role, but we have to make sure that it makes sense and doesn't eliminate jobs and increase pollution inadvertently.

Thank you, I yield back my time, Mr. Chairman.

Mr. WHITFIELD. Ms. Capps, you are recognized for 5 minutes.

Mrs. CAPPS. Thank you very much, and thank you for testimony of each of you. I am going to be brief and concise because I know my colleague, Mr. Markey, has some questions too. These will be focused at you, Mr. Walke.

Yesterday Subcommittee Chairman Whitfield confirmed that legislation to delay air toxic standards will be introduced after the congressional recess. We have heard from some in the energy industry that a delay is needed because of "importance of a smooth transition and more deliberate schedule" to ease the strain on industry and reduce risks to consumers with the proposed rules for utilities. If the proposed standards to reduce air toxics from power plants were delayed by even a year, a single year, what would it mean for public health? Give us a couple of examples.

Mr. WALKE. I would be happy to, Congresswoman Capps.

What we have found from EPA's own data is that the delay of these three rules by even a single year would result in up to 26,000 premature deaths, 17,000 non-fatal heart attacks, about 180,000 asthma attacks, and approximately 330,000 cases of upper and lower respiratory systems. These would be one of the most profound retreats from the Clean Air Act protections ever to be considered by this body.

Mrs. CAPPS. Mr. Walke, we also hear from the industry and increasingly from my colleagues on the other side of the aisle that EPA is overreaching with its air toxics standards. I myself disagree with that statement. I have maintained that these standards reflect EPA doing its job. Do you believe EPA is overreaching with its proposed air toxic standards for power plants?

Mr. WALKE. I do not. The agency is following well-established law that unfortunately it was created by the courts in the last decade when they overturned far greater overreaching by the Bush administration that——

Mrs. CAPPS. That is what I wanted to turn to next. As EPA has moved to implement the law and issue standards to control air toxics from power plants, go further to illustrate—I wanted to find has there ever been an action that can be characterized as an EPA overreach, and finish that description that you were giving.

Mr. WALKE. Yes, absolutely. EPA under the Bush administration violated the toxics provision of the Clean Air Act at least in 11 or 12 cases, all of which are represented before us today. One of them EPA even realized it couldn't defend, so it took back the cement rule. In several of those cases, the courts found themselves resorting to quoting two different works of Lewis Carroll, including Alice in Wonderland in the power plant case, because they were so profoundly disgusted by the end of the second term as to how many times the law had been broken. It really has never been seen in the Clean Air Act case law in quite the way it played out under that administration.

Mrs. CAPPS. And finally, Mr. Walke, some folks today have said that the EPA standards for boilers and cement factories are just too hard to achieve, and that the industry will not have enough time to meet the long-awaited standards. You disagree. Now just to use a few seconds and maybe a minute to comment on these claims that they have made so we can get this on the record.

Mr. WALKE. Sure. The Clean Air Act gives up to 4 years, that includes a 1-year extension if it is necessary, to install the controls. We have had over 100 of these standards issued in the past 20 years, covering 400 to 500 industries. It is really these laggards who have benefited from lawbreaking by the last administration that are now complying with these rules for the first time, some 15 years overdue. The law gives them the flexibility. The boilers rule came in far more flexibly and cost effectively than anyone anticipated. Mr. Bradley has testified that the power plant rule is the same. The cement final rule is weaker than the proposed rule. EPA does not agree with the Portland Cement Association's claims about closures and job losses. These are hotly disputed topics, and I just want you to be aware that it is very important to have EPA appear as a witness, as Chairman Whitfield has invited at a future hearing.

Mrs. CAPPS. I thank you and I will yield back now the balance of my time.

Mr. WHITFIELD. Thank you very much.

Mrs. CAPPS. I will yield to, if it is OK, to Mr. Markey.

Mr. MARKEY. I thank the gentlelady very much.

Mr. Bradley, in 2004 Governor Mitt Romney of Massachusetts adopted regulations to control mercury from coal-fired power plants in Massachusetts that require 85 percent of mercury emissions to be captured by 2008. Were utilities able to keep the lights on while this standard was being met?

Mr. BRADLEY. Absolutely.

Mr. MARKEY. Did the geniuses at MIT have to invent some new alloy or exotic technology so the coal-fired power plants in Massachusetts can meet this standard?

Mr. BRADLEY. Not that I am aware of.

Mr. MARKEY. Is this standard now being met by 12 other States in the union?

Mr. BRADLEY. Comparable requirements are in place in 12 States.

Mr. MARKEY. Are the technologies that were installed in Massachusetts available and economically viable for use in coal-fired power plants in other States?

Mr. BRADLEY. Absolutely.

Mr. MARKEY. The Southern Company says they can build two new nuclear power plants and guarantee the safety of people, but they can't really figure out how to install these technologies that already exist that would protect against the poisoning of the children in our country. Do you think that Southern Company should be able to figure that out if they can build two new nuclear power plants in our country?

Mr. BRADLEY. I think they have a tremendous track record——

Mr. MARKEY. I do, too.

Mr. BRADLEY [continuing]. And in the end, they will figure it out.

Mr. MARKEY. I just—I think this can't-do attitude that is not like President Kennedy's can-do attitude to put a man on the Moon with alloys that had not yet been invented, but here the technology has already been invented and are already installed. We are not asking them to invent anything, but yet, it is kind of disconcerting to me to hear the Southern Company and others here saying they can't figure out how to install something while guaranteeing us they can make nuclear power plants safe, after Fukushima, without even waiting until they really install all the lessons from Fukushima. So that is a great concern to me, and I would hope that this can't-do Republican majority can turn into a can-do majority and take existing technologies and mandate that we can install them, but I am afraid that those public health lessons are going to be lost upon them.

I thank the gentlelady and I thank the chairman for his——

Mr. WHITFIELD. I am glad the gentleman from Massachusetts is so intimately involved with Southern Company and knows their facts.

Mr. MARKEY. I love the Southern Company. It is my favorite utility to talk to.

Mr. WHITFIELD. Mr. Scalise, I am going to recognize you. We have votes on the floor and I am trying to accommodate everyone so that—we are going to have three series of votes, and I am sure these people don't want to wait another 2 hours. So I will recognize Mr. Scalise for——

Mr. SCALISE. Sure. Thank you, Mr. Chairman. I appreciate that. I will try to go rapid fire. I hope the gentleman from Massachusetts will join with us in supporting a comprehensive all-of-the-above energy strategy, because I think we know we have got resources in our country for wind, solar, nuclear, a whole lot more oil and gas, billions and billions of barrels that are still out there that can explored for in a safe way. That can generate thousands of jobs, generate billions of dollars to our economy so that we can reduce our deficit while not shipping more jobs to other countries and while not making our country more dependent on foreign oil.

I want to ask Mr. Fanning, in your testimony you talked about the impacts on the economy of some of these EPA proposals and regulations coming down. Can you expand a little bit upon the true impacts to the economy that would be imposed if this were to go forward?

Mr. FANNING. Yes, thank you. I would be delighted. The far-reaching impacts here are pretty significant. We have already talked about the direct impact; that is, we think as a result of this proposed rule as it stands, at least for the Southeast, 25 percent increase in prices, but that really doesn't even begin to speak to the total impact. When we think about jobs and the economy, it is pretty clear that a conservative estimate of the loss of jobs when you move from coal to gas is about a six-to-one ratio, just to flesh that out a bit. For a 500 megawatt coal plant, it employs about 300 people. A 500 megawatt gas plant employs about 50 people. So you would move from 300 jobs to about 50 jobs. You lose net 250. If you extend that to the notion that we may lose 70,000 megawatts across the United States, that is the direct loss of 35,000 high-paying jobs. That doesn't even begin to address the issue of the first-, second-, third-tier suppliers, railroads, mines, equipment vendors, et cetera. It doesn't even begin to address the amount of jobs lost as a result of a less competitive global economy.

Mr. SCALISE. And that is what I wanted to ask as my final question before my time expires. We talk about international competitiveness, and of course, our American companies, we want them to be successful not only here in America, but for those who do operate in other countries, we want them to be able to play on a level playing field. Right now, they are being pushed further and further out in their ability to compete globally because of some of the things happening by this administration, EPA, and others that are actually making it harder for American companies to survive. So if you have regulations like this that basically say if you are an American company, you can't even manufacture, your electricity costs would be so high if you do business in America, what does that mean to us internationally as other countries would love to take our jobs? Unfortunately, other countries are already taking too many of those jobs. It seems like an EPA regulation like this would push even more tens of thousands of jobs from America out of our country.

Mr. FANNING. I think you make an excellent point, and I would just use this notion, that as we don't consume coal in America and we export it, we will export jobs along with it.

Mr. SCALISE. And obviously, they don't have the same environmental protections that we enjoy today, so the things that EPA seems to be concerned about would actually be exponentially increased if those jobs here in America would go to those foreign countries like China and India.

Mr. FANNING. If I could just add one more quick social impact. As we close down these plants, we will visit economic damage on local communities. I just got a letter yesterday from Putnam County, Georgia, that if we close down Branch Units 1 through 4 in that county, we will reduce their tax base by about 19 percent.

Mr. SCALISE. Mr. Chairman, if I can maybe move unanimous consent to have that letter introduced into the record? Thank you and I yield back.

Mr. WHITFIELD. Without objection.

[The information follows:]

PUTNAM COUNTY BOARD OF COMMISSIONERS
108 South Madison Avenue, Suite 300 - Eatonton, Georgia 31024
Telephone (706) 485-5826 - FAX (706) 923-2345
Website: www.putnamcountyga.us

Chairman:
Tom Thompson

District One:
John A. Clements, Jr.

District Two:
Janie B. Reid

District Three:
Alan Foster

District Four:
Billy Webster

July 1, 2011

Representative Fred Upton
The Committee on Energy and Commerce
2125 Rayburn Housing Office Building
Washington, DC 20515

Dear Representative Upton:

Allow us to begin this correspondence by thanking you for your tenacious defense of American business and industry in the face of what would be overburdening environmental regulations by the US EPA. We believe we have an illustration in Georgia that will assist in your advancement of that defense.

As you are certainly aware, the environment is cleaner than it has been in 40 years. We have no oppositions to more stringent rules that yield continuing environmental improvements if those improvements are justified, but balance and pace of change are essential to maintain Georgia's industrial base and associated jobs and tax revenues. Unrealistic environmental rules would result in the exportation of jobs around the globe with no commensurate environmental improvements. To that concern, we the Putnam County Board of Commissioners would like to offer you a local case study in Georgia.

To frame the point, Putnam County, located about 70 miles southeast of Atlanta, collected almost $34 million in sales and property taxes in 2010. Georgia Power, who operates four coal-fired units in our community, directly paid $4.5 million of that amount or almost 13% of the total taxes collected in the County. This does not include the indirect economic infusion from the hundreds of high-paying jobs that exist in our region because of the operations of the facility.

It is our understanding that pending environmental rules at the federal level could force the closure of this facility despite past and future planned investments on environmental controls. Closure of the facility would be devastating to our community and its citizens. This economic risk comes at a time when every air quality monitor in Georgia is recording compliance with existing air quality rules.

Page 2
July 1, 2011
Representative Fred Upton

Great environmental progress is being made in Georgia because of the considerable efforts of businesses and individual citizens. In these economic times, there must be balance regarding ever-tightening environmental regulations with respect to the impact to communities, jobs, and tax revenues. Please keep up your efforts in advancing that balance.

Respectfully,

Board of Commissioners of Putnam County

Tom Thompson
Chairman Tom Thompson

John A. Clements
Commissioner John A. Clements, Jr.

Alan Foster
Commissioner Alan Foster

Janie B. Reid
Commissioner Janie B. Reid

Billy Webster
Commissioner Billy Webster

cc: Lisa Jackson – Administrator, US EPA
Georgia Congressional Delegation

Separate letter to:

Senator James M. Inhofe
Ranking Member
Senate Environment and Public Works Committee
456 Dirksen Senate Office Building
Washington, DC 20510-6175

Mr. WHITFIELD. Well, that concludes today's hearing. As I said, we have a number of votes on the floor relating to the budget, but I want to thank all of you for coming. I look forward to working with our friends on the—our Democratic friends to craft legislation that can accommodate some of the concerns we have heard today. And with that, the hearing is concluded and the record will remain open for 10 days for additional material or questions. Thank you.

[Whereupon, at 11:30 a.m., the subcommittee was adjourned.]

[Material submitted for inclusion in the record follows:]

Statement of Representative John D. Dingell
April 15, 2011
House Committee on Energy and Commerce
Subcommittee on Energy and Power
"The American Energy Initiative"
9 am, 2322 RHOB

Mr. Chairman – I thank you for holding this important hearing today. I want to extend a special welcome to Tony Early from DTE Energy. Tony is a dear friend and an outstanding citizen and community leader. Tony, welcome to the Energy and Commerce Committee.

The utility industry faces a number of regulations coming down the pike. We need to achieve a reduction in air pollutants, and I strongly feel we can do this very meritorious reduction while also providing industry with the time and even some flexibility to get those reductions in a cost effective manner.

I don't have to tell anybody here about the state of Michigan's economy. We were among the first states hit in the recession and we were among the hardest hit. We cannot afford to lose any more jobs. We cannot afford to watch factories relocate to places with cheaper energy prices.

Without getting into the details of the proposed rule for hazardous pollutants from utilities, I truly believe there is a bipartisan majority that could support a narrow legislative fix to extend the implementation and compliance time. Moreover, I would like to work with my colleagues on a solution to the problem of old power plants that are going to be shuttered. It simply doesn't make sense to invest heavily in these facilities. What seems to make sense to me is some kind of system by which they are exempted from this rule with an iron-clad agreement that certain facilities be taken off-line by a date certain.

Dingell

I also note that EPA had wanted additional time to finish the boiler MACT rule, but they were required by the courts to put the rule out this spring. It seems that it would be a good idea for us to give EPA the time they wisely requested from the court.

I would like to take a moment to express my dismay with the fact that EPA is not here to testify. It is my understanding that they were invited via a voicemail message left with a junior staffer very late Friday night, less than a week before this hearing. This Committee has a long and distinguished history of giving witnesses the maximum notice of hearings and of working with important witnesses to ensure their availability. It is in all our interest to make sure we have all the information we need to make intelligent and informed decisions on major policy initiatives. I urge the majority to keep up with that long-standing tradition – it is just one of the things that makes Energy and Commerce a great committee.

Finally, Mr. Chairman, I urge the majority to reach out and work in a bipartisan manner on this important matter, and for the love of God, don't overload this thing with extraneous material. We can and we should do something that protects the environment and protects jobs.

Responses from Mr. Tom Fanning
Chairman, President, and CEO of Southern Company
June 3, 2011

The Honorable Henry A. Waxman

1. **In your responses to questions at the hearing you claimed that EPA rules would lead to 70 to 80 GW of coal fired generation retirements.**

   a. **Please identify the sources or studies on which you rely for this claim.**

   b. **For each study, for each regulatory requirement analyzed as driving generation retirements, please identify whether the most recent version of the regulatory requirement proposed or finalized by EPA differs from the version of the regulatory requirement modeled in the analysis in terms of the stringency of emissions limits, the technologies required to comply, the inclusion or exclusion of flexible approaches, timing of the compliance requirements, or other material differences. Also identify any regulatory requirements included in the analysis for which EPA has not yet issued a proposal.**

   c. **For each regulatory requirement analyzed, please provide the assumptions regarding the content of the requirement used in the analysis. For example, for the 316(b) water rule, provide the expected technology requirements and timing relevant to the projected retirements. For any regulatory requirement that has not yet been proposed by EPA, please provide the basis for the assumptions regarding the content of the requirement used in the analysis, as well as identifying those assumptions.**

   d. **In light of the differences between the modeled versions of the regulatory requirements and EPA's most recent actual proposed or final requirements, how relevant are the analytical conclusions of the study or studies? If the analyses were updated to reflect the rules as actually proposed or finalized by EPA, do you believe it would still project almost 80 GW of retirements? If yes, what is the basis for that view?**

The retirements are based on the EEI report released in January 2011. The report represents a collaborative effort to model EPA rules and understand the combined effect that pending regulations for air quality, coal combustion residuals, cooling water intake structures and greenhouse gases will have on the electric industry. However, several other groups have also examined the impact of EPA's expected rules on coal-fired generation retirements and those analyses also support the range above. NERC[i] considered two scenarios, a moderate case and a strict case[1], for the combined impacts of the EGU MACT, the CATR, the CCB, and the 316(b) regulations. Bernstein Research[ii] and Credit Suisse[iii] considered the EGU MACT and the CATR regulations. The results of these reports, which have projected as many as 70 GWs of retirements by 2015, are shown in the chart below.

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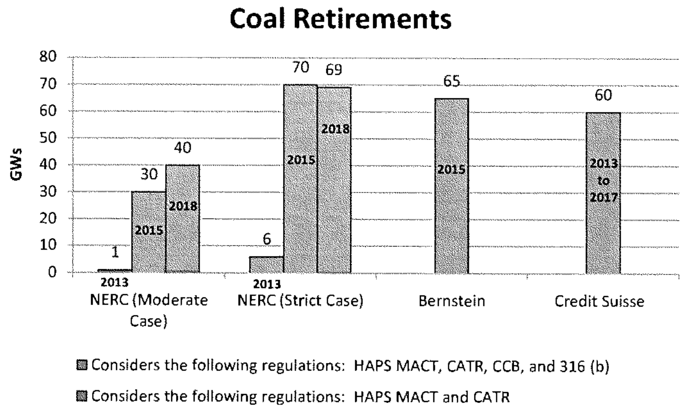
[1] NERC's strict case reflects a higher increase in costs with more stringent requirements for the proposed rules than its moderate case.



Note: Coal Retirements – Projected U.S. coal retirements from the following reports: the NERC Report, the Bernstein Research Report, and the Credit Suisse Report

Additionally, EIA recently released the AEO2011 which included a number of sensitivities to look at the future requirements. EIA's analysis differed from EEI's in that it did not include a comprehensive analysis of the combined impacts of all future regulations. Even with this major difference, the coal plant retirements in EIA's sensitivities ranged from 14 GW to 135 GW. Because EIA's work did not evaluate the cumulative impact of all requirements the bottom of the range is expected to be low. When compared to EIA and other analyses the EEI report's 70-80 GW is within the expected range of coal plant retirements.

The EEI report was the culmination of a year-long study and represents a collaborative effort of EEI's membership. The EEI report assumed control requirements for a myriad of rules, as well as, sensitivities around those assumptions. When making retirement decisions all the current and future requirements must be included, but the decision to retire will be triggered by the first requirement. Although EPA released some proposals since the completion of the study, a review of those proposals does not significantly change the control assumptions. For example, requirements assumed for air controls were not only related to the Clean Air Transport Rule and the Utility MACT rule, but also the National Ambient Air Quality Standards for SO_2, NO_2, particulate matter, ozone and the Clean Air Visibility Rule. The recent Utility MACT proposal has emissions limits stringent enough to require the set of controls assumed in the EEI report, and the timing is so restrictive that installation of those controls will be difficult. Given the restrictive timing, options will also be limited to proven technologies that have demonstrated performance and reliability for controlling emissions to these stringent limits and to limits expected for other new rulemakings.

Base and alternate regulatory scenarios for water, ash and carbon dioxide were also created to bracket the range of possible outcomes, and the recent proposals are still within the range modeled. The recent 316(b) proposal did not mandate closed-loop cooling or cooling towers like the base water scenario, but the alternate water case that was run represents a range that brackets the outcome consistent with the proposal. Comparing the two cases in which the water requirements went from requiring all fossil and nuclear facilities to have closed-loop cooling or cooling towers in the next 10-15 years (base) to a case where only a subset of large units on sensitive water bodies were required to install closed-loop cooling or cooling towers (alternate) changed the total retirements by only 1 GW.

The exact compliance date for each individual control requirement is not as important to the retirement timing as is the date of the first requirement; particularly when so many requirements are impacting the generation fleet over such a short timeframe. The model looks forward, as electric utility companies must, and compares the cost of continuing to operate to the value of the unit. If it is determined that the cost to continue operation is not the economic decision, then the retirement will occur prior to the first control requirement, thus avoiding the first investment.

The recent proposals continue to support the range of assumptions modeled and the results from the study. Focusing on any single requirement is incomplete and does not give the full picture of what the industry is facing. The retirements are based on the cumulative impact of a number of environmental requirements and the suite of controls and risks that those requirements will impose on the units.

2. **Of the 70 to 80 GW of projected retirements, identify how many GW of retirements have already been announced. Of the remainder, to what degree are the projected retirements dependent on the price of natural gas and the remaining useful life of the facilities?**

At the time of the EEI modeling, ICF had 5.5 GW of planned retirements in their case by 2015. There have been announcements since the modeling was completed. The total burden on the industry is not lessened by the announcement of retirements since they still occur within the same timeframe and will put the same pressure on competition for resources. Also, the announced retirements do not meet timelines consistent with the recent proposals. For example, TVA recently announced retirements, through a settlement agreement, of 18 units that will phase in over the next several years, but the final four units are not required to retire until December 31, 2017. That is beyond the compliance date for the proposed Utility MACT and those units could be forced into retirement early if they don't meet the mandatory standards by the regulatory deadlines. Louisville Gas and Electric Co. and Kentucky Utilities also released plans to retire 3 coal units whose combined capacity is almost 1,000 MW.

Natural gas prices and remaining life are key to retirement analysis along with other factors including, but not limited to: coal prices, the relative difference between fuel prices, capital cost expenditures, operating costs, future environmental requirements and anything that impacts the continuing to operate cost of a unit.

3. **In your responses to questions at the hearing you claimed that the utility air toxics rule would lead to 25% price increases for Southern Company customers. Please provide the cost support for this statement, including the capital and O&M costs assumed, the amortization period, the cost breakdown by rate class, the baseline rate assumptions, and the calculation of the 25% price increase.**

The estimated increase in electricity price cited was based on an additional analysis, by Smith, et al.[2], of a scenario examined by ICF International for the Edison Electric Institute (EEI). The additional analysis estimated price increases of about 25% for an average electricity consumer in the Southeast US region in 2020, regardless of the rate class. As discussed above in response to Question 1, the report based on ICF analysis for EEI ("EEI report") estimated the impacts on electricity generation of several combinations of impending environmental requirements, including a combination with a CO_2 requirement. The EEI report did not discuss the effects of the air toxics rule alone. The EEI report also did not provide estimates of electricity price impacts. The costs and other assumptions supporting the EEI report are detailed within the report itself, which has been submitted along with the Company's responses to these questions. The Smith, et al., analysis considered a set of assumptions similar to those adopted for the analysis supporting the EEI report. The capital, O&M costs and other assumptions used by Smith, et al., are given in the attached document, "Impacts of environmental requirements - Assumptions.pdf" and the key results are summarized in the attached document "Impacts of environmental requirements.pdf". Smith, et al., estimated that the costs of complying with the comprehensive set of impending environmental requirements, including a CO_2 requirement, would result in electricity prices for an average electricity consumer in the Southeast US region in 2020 being about 25% higher than in the reference projection.

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[2] Smith, A., S. Bloomberg, P. Bernstein, M. Yuan and D. Montgomery, "Economic impacts of environmental requirements", analysis by Charles River Associates for Southern Company, March, 2011.

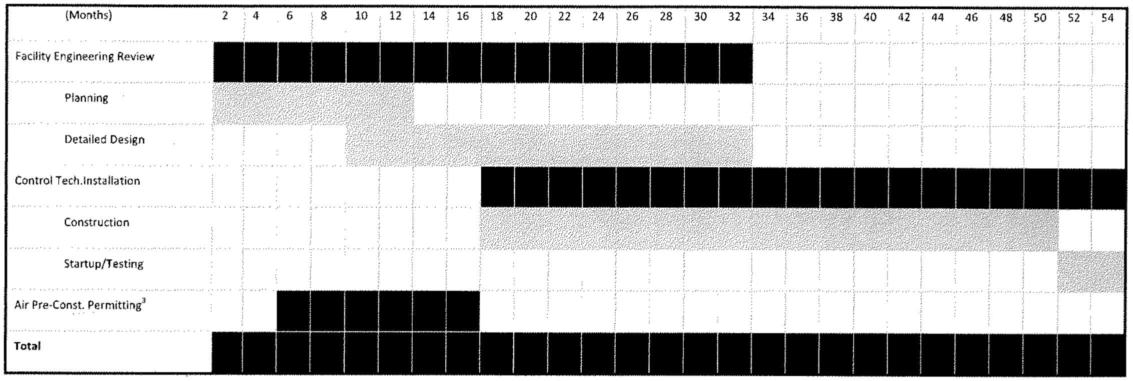
4. **In your written testimony you stated that, "Southern Company's historical experience, which is the most extensive in the industry, shows it takes an average of 54 months to install a single scrubber retrofit." Please provide the information supporting the estimate of a 54 month average installation time.**

Southern Company's Experience Installing FGDs Shows That the Average Time Required to Complete a Single FGD is 54 Months

Between 2003 and 2010 Southern Company installed 15 FGDs at the following facilities: Bowen 1-4 (4 FGDs), Wansley 1-2 (2 FGDs), Barry 5 (1 FGD), Gaston 5 (1 FGD), Crist 4-7 (1 FGD), Gorgas 8-10 (1 FGD), Hammond 1-4 (1 FGD), and Miller 1-4 (4 FGDs). Our experience shows that the time required to complete a single FGD project ranges from 40 to 69 months, with an average schedule of 54 months. This process includes all of the steps in Figure 1, from planning to startup.

Figure I below illustrates Southern Company's average project schedule for a single FGD retrofit (Note: this schedule does not account for multiple control installations occurring at the same facility at the same time). While there are some parts of the project schedule within permitting, engineering and design, and construction that can be overlapped, some must be completed in sequence and cannot be performed in parallel. The timelines below illustrate an average FGD installation time based on Southern Company's historical project experience and show some of the overlap that can occur. There are further schedule and cost pressures when constructing multiple controls at one unit at the same time, constructing multiple controls at multiple units at one site at the same time, or when managing major construction programs across many sites at the same time. Such projects would likely incur additional logistical difficulties and increase the overall project duration and cost.

Figure 1. Southern Company's Historical Experience Illustrates that 54 Months are Required for a Typical FGD Installation



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[3] This is only non-PSD construction permitting (state construction permits, if necessary). PSD permitting would add length to the overall schedule and likely become a critical path item.

We have found that executing several of these projects simultaneously can complicate logistics; stress the supply chain for major equipment; and compete for limited craft labor resources - all of which can significantly extend project duration.[4] These factors, as well as location-specific engineering, scope, and retrofit difficulties, account for the large variance in project durations.

Southern Company's Quickest FGD Installation Required 40 Months

The FGD at Plant Hammond Units 1-4 (a single FGD vessel serving all four units) was the quickest installation that Southern Company has achieved, and that project took 40 months. Some of the reasons for the shorter-than-average schedule for this project include:

- Typical Southern Company FGD projects would allow time for bidding the project to multiple contractors (i.e., inquiry preparation, bid preparation, evaluation, and contract negotiations) in order to ensure that we receive the best product for prudent cost and dependable service from contractors. The PSC for each state oversees and can disapprove of imprudent expenditures. However, the FGD at Hammond was purchased on a sole source basis and did not require extra time for the bidding process. This approach was made possible by leveraging work from previous projects with the same FGD technology and was a special case in which the Company was able to ensure prudent costs without going through the bid process.
- The shorter execution schedule necessitated "just in time engineering designs" to support the construction effort. While this might be possible, the construction risk factors (cost) are higher due to in-field reworks and errors/omissions.
- One factor that often slows the construction is the limited amount of work space—or site congestion. Specific to the Hammond site, the FGD equipment was located on both the north and south side of the plant's railroad tracks. This relieved site congestion and allowed simultaneous construction of the FGD Island (south side of tracks) from the limestone preparation and gypsum dewatering (north side of tracks). Additionally, the FGD Island was located in an existing parking lot and required minimal relocations and site preparation.
- Although the FGD was completed in 40 months, the expedited schedule had an influence on material availability. We were not able to get our standard & preferred material for the FGD outlet hood and, instead, had to select a lower corrosion resistance material in order to support the schedule. While this has no impact on the performance of the FGD, this section of the equipment may require more frequent maintenance and care in the future.
- Multiple boilers on a single FGD vessel require an open vent stack for draft system protection. Hammond was able to use a stack at one of the existing units that did not require any type of refurbishment, thus decreasing the total project duration. Further, the four units at Hammond were small enough in size to allow all units to be served by constructing a single FGD vessel. This is not necessarily possible for sites with multiple larger units.

Southern Company's Longest FGD Installation Required 69 Months

The FGD at Plant Gorgas Units 8-10 was one of the company's first FGD installations and took 69 months to complete. Some of the reasons for the duration of this project were:

- The Gorgas FGD project was one of our first FGD projects and necessarily required a lot of initial preparation time for developing an inquiry package for the competitive bid process, including supplier qualification (i.e., there was no previous work performed that could be leveraged in an effort to reduce the schedule). Additionally, the commercial negotiations for the contract required several months. Although our more recent experiences have been leveraged to reduce the timing for the competitive bid process, other site specific factors made this FGD installation longer than average.
- The Gorgas site required extensive site preparation. An entire mountain had to be removed to create an available footprint for the FGD Island.

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[4] This is true within the Southern Company system as well as competing nationally for resources/equipment.

- Because this FGD included three units, the retrofit for units 8 and 9 required the ID fan manifold to be replaced, which would not be typical for most retrofits.
- Southern Company overlaps phases of construction and installation where possible. However, the Gorgas site was very congested and the construction of the new chimney and the Stebbins tile FGD vessel had to proceed sequentially rather than in parallel. This is due to the safety exclusion zone required around the new stack while under construction.
- Similar to Hammond, Gorgas also serves multiple boilers on a single FGD vessel which requires an open vent stack for draft system protection. The Gorgas vent stack required extensive refurbishment including a new flue and a new breach.

5. For the scrubber installation projects listed below please provide the following: (1) start and end date for engineering and design work; (2) start and end date (or projected end date) for permitting; (3) start and end date (or projected end date) for construction; (4) number of jobs created (or projected) from the project; (5) total capital costs (or projected capital costs) for the project; (6) rate impact (or projected rate impact) for the project; and (7) the degree to which project would help the plant or unit achieve the proposed emissions limits of the utility air toxics rule.

Florida Power's Plant Crist scrubber project
Georgia Power's Plant Wansley scrubber project
Mississippi Power's Plant Daniel scrubber project

The information requested for these projects is presented in the table below. The Plant Crist scrubber project involved a single scrubber vessel installed on 4 units. This project was completed as a part of Gulf Power's compliance strategy for CAIR and CAMR, both of which have been vacated. The Plant Wansley scrubber project involved two scrubber vessels installed on two units as required by the Georgia Multi-Pollutant Rule. The Plant Daniel scrubber project is projected to involve two scrubber vessels installed on two units, as a part of Mississippi Power's compliance strategy for the proposed MACT rule and other air rules. Engineering dates begin with the conceptual planning phase and end with the completion of detailed design. The start and end date (or projected end date) for permitting represents air construction permitting only and does not include other potentially necessary environmental permits for construction or operation of the scrubbers. Nor does it include time for state regulatory / public service commission approval, which may vary by state and operating company but which can add significant time to the overall process and usually does not start until a final rule is in place that drives the control installation. Construction dates begin with field mobilization and end with the operation of scrubber equipment. The jobs created information presents both the short-term, temporary construction jobs associated with each project and are based on contractor man-hours expended on the job divided by 2080 man-hours to give representative "man-years" as well as the permanent, on-site jobs dedicated to scrubber O&M at the facilities. Total capital costs include total installed cost.

All information presented for the Plant Daniel scrubber project is projected as construction has not yet begun for this project. This project exemplifies some of the challenges that the utility industry faces in early planning of controls. Engineering and permitting / regulatory approval work began in 2010. As of the date of this response, neither air construction permitting nor regulatory / public service commission approval of the project has been obtained, partially attributable to the lack of a final MACT rule and other rules that would provide certainty in the decision to install the controls. Because of the lack of approval, the overall initial project schedule has been delayed and the project, based on current schedule estimates, cannot be completed until mid 2015.

Rate impacts are typically not calculated on a project-by-project basis and may differ in terms of how they are determined between the different states / operating companies associated with each project. The responses below provide the context for rate impacts for each project.

	Plant Crist [1]	Plant Wansley [2]	Plant Daniel [3]
(1) Start and end date for engineering and design work	1/2006 to 7/2009 [4]	2/2004 to 10/2007 [4]	6/2010 to 3/2013 [4]
(2) Start and end date (or projected end date) for permitting	5/2006 to 5/2007 (Air construction permitting only: beginning of application preparation to issuance of construction permit)	1/2005 to 1/2006 (Air construction permitting only: beginning of application preparation to issuance of construction permit)	8/2010 to 6/2011 (Air construction permitting only: beginning of application preparation to expected issuance of construction permit)
(3) Start and end date (or projected end date) for construction	6/2007 to 12/2009 [5]	1/2006 to 7/2009 [5]	6/2011 to 5/2015 [5]
(4) number of jobs created (or projected) from the project	1,653 [6] temporary construction jobs on a "man-year" basis. 28 permanent jobs dedicated to scrubber O&M.	1,595 [6] temporary construction jobs on a "man-year" basis. 15 permanent jobs dedicated to scrubber O&M.	989 [6] expected temporary construction jobs on a "man-year" basis. 21 expected permanent jobs dedicated to scrubber O&M.
(5) total capital costs (or projected capital costs) for the project	$ 651M [7]	$ 489M [7]	$ 625M [7]
(6) rate impact (or projected rate impact) for the project	The four coal-fired units at Gulf Power's Plant Crist were retrofitted with a scrubber that went into commercial operation during December 2009. The 2010 actual annual revenue requirements, including operations and maintenance (O&M) expenses, for the Crist Scrubber were approximately $104 million of which approximately $100 million were collected from retail customers. This represented approximately 8% of Gulf Power's 2010 total retail revenues. Gulf Power recovers the retail portion of its revenue requirements related to the Crist Scrubber from retail customers through an annual process that sets rates for a calendar year based on the projected revenue requirements associated with the project, and incorporates an adjustment in subsequent filings designed to true up the projected revenue requirements for the prior year to the actual revenue requirements in that year.	The Environmental Compliance Cost Recovery Schedule (ECCR), as approved by the Georgia Public Service Commission, is used to recover capital costs and operating and maintenance costs associated with government mandated environmental controls. The total yearly ECCR amount in current rates is $381,663,412, which comes to $3.80 per month, or 3.2% of the total bill, for the typical residential customer averaging 1,000 kWhs per month. Rate impacts are not calculated on a project-by-project basis. The current ECCR tariff is in effect for the period 2011-2013 as approved by the Georgia PSC in the 2010 rate case and reflects Georgia Power's ownership share of the capital and operating and maintenance costs associated with the Wansley scrubbers, as well as costs for other environmental controls that are in service. Georgia Power owns 53.5% of the Wansley units.	The two coal-fired generating units at Plant Daniel are jointly owned by Mississippi Power and Gulf Power. Current projections are for the scrubber project to be placed into service in 2015. Each company expects to recover its respective share of the revenue requirements associated with the project, both capital and O&M, through their respective state and federal regulated rates including state specific mechanisms addressing recovery of environmental compliance costs from retail customers. Mississippi Power Company has estimated the total cost of the scrubber project for Plant Daniel Units 1 & 2 will be in excess of $625 million. The project is proposed in order to begin the process of complying with various environmental mandates. The Company's retail rates, approved by the Mississippi PSC, provide means for adjustments that allow for the recovery of costs associated with environmental laws and regulations through an environmental rate mechanism. A certificate of public convenience and necessity to authorize construction of the project is under consideration by the Mississippi Public Service Commission. The Company's retail residential bills with the Daniel scrubber construction project are projected to be impacted by about 25 cents per month per thousand kWh in 2011 reaching a maximum of about $4.21 per month in 2015. These projections reflect the Company's 50% ownership interest in Plant Daniel Units 1 & 2 and include costs for the scrubbers only. Gulf Power, based on its 50% ownership interest in Plant Daniel, projects potential rate impacts between 4% and 6% of retail

			revenues during the first year of commercial operation of the scrubber project.
(7) the degree to which project would help plant or unit achieve the proposed emissions limits of the utility air toxics rule	These scrubber projects would help the respective units reduce some of the emissions regulated in the proposed MACT Rule but will not by themselves, or even in combination with other controls already installed on some of the units resulting in co-benefit emission reductions, achieve compliance with all of the limits for all pollutants contained in the proposed rule. Significant investment in additional controls (likely baghouses), as well as additional continuous emission monitoring equipment will be required for all of these units. This investment is in addition to the significant capital shown above that has already been invested in these units.		

[1] The Plant Crist scrubber project involved a single scrubber vessel installed on 4 units.

[2] The Plant Wansley scrubber project involved two scrubber vessels installed on two units.

[3] The Plant Daniel scrubber project is projected to involve two scrubber vessels installed on two units.

[4] Engineering dates begin with conceptual planning phase and end with completion of detailed design.

[5] Construction dates begin with field mobilization and end with operation of scrubber equipment.

[6] Jobs created represent the contractor man-hours expended on the job divided by 2080 man-hours to give representative "man-years".

[7] Total capital costs include total installed cost.

6. The web site for Alabama Power (http://www.alabamapower.com/environment/air.asp) lists a number of recent air pollution control installations. For the projects listed below, please provide the following information: (1) start and end date for engineering and design work; (2) start and end date for permitting; (3) start and end date for construction; (4) number of jobs created from the project; (5) total capital costs for the project; (6) rate impact for the project; and (7) the degree to which project would help the plant or unit achieve the proposed emissions limits of the utility air toxics rule.

Clean-air improvements at Alabama Power plants

Plant Unit	**County**	**Date of Service**
Scrubbers		
Gorgas 8-10	**Walker**	**January 2008**
Gaston 5	**Shelby**	**March 2010**
Miller 1	**Jefferson**	**January 2011**
Miller 2	**Jefferson**	**April2010**
Miller 3	**Jefferson**	**December 2009**
Miller 4	**Jefferson**	**January 2010**
Barry 5	**Mobile**	**February 2010**

The information requested for these projects is presented in the table below. These projects were completed as part of Alabama Power's compliance strategy for the Acid Rain Program, the PM2.5 standard, CAIR, and CAMR. Engineering dates begin with the conceptual planning phase and end with the completion of detailed design. The start and end date (or projected end date) for permitting represents air construction permitting only and does not include other potentially necessary environmental permits for construction or operation of the scrubbers. Nor does it include time for state regulatory / public service commission approval, which may vary by state and operating company but which can add significant time to the overall process and usually does not start until a final rule is in place that drives the control installation. Construction dates begin with field mobilization and end with the operation of scrubber equipment. The jobs created information presents both the short-term, temporary construction jobs associated with each project and are based on contractor man-hours expended on the job divided by 2080 man-hours to give representative "man-years" as well as the permanent, on-site jobs dedicated to scrubber O&M at the facilities. Total capital costs include total installed cost.

Rate impacts are typically not calculated on a project-by-project basis. The response below provides the context for rate impacts for each / all projects.

	Gorgas 8-10[1]	Gaston 5[1]	Miller 1[1]	Miller 2[1]	Miller 3[1]	Miller 4[1]	Barry 5[1]
(1) Start and end date for engineering and design work	4/2002 to 4/2006[2]	1/2005 to 8/2009[2]	5/2006 to 6/2009[2]	5/2006 to 3/2009[2]	1/2005 to 10/2007[2]	1/2005 to 10/2007[2]	3/2005 to 11/2008[2]
(2) Start and end date (or projected end date) for permitting	10/2004 to 5/2005[3]	12/2004 to 2/2007[3]	3/2006 to 3/2007[3]	3/2006 to 3/2007[3]	3/2006 to 3/2007[3]	3/2006 to 3/2007[3]	10/2006 to 5/2008[3]
(3) Start and end date (or projected end date) for construction	1/2005 to 12/2007[4]	9/2007 to 3/2010[4]	12/2007 to 1/2011[4]	12/2007 to 4/2010[4]	8/2006 to 12/2009[4]	8/2006 to 1/2010[4]	9/2007 to 2/2010[4]
(4) number of jobs created (or projected) from the project	728[5] temporary construction jobs on a "man-year" basis. 13 permanent jobs dedicated to scrubber O&M.	865[5] temporary construction jobs on a "man-year" basis. 14 permanent jobs dedicated to scrubber O&M.	2,187[5] temporary construction jobs on a "man-year" basis. 24 permanent jobs dedicated to scrubber O&M.				788[5] temporary construction jobs on a "man-year" basis. 17 permanent jobs dedicated to scrubber O&M.
(5) total capital costs (or projected capital costs) for the project	$ 267M[6]	$ 266M[6]	$ 833M[6]				$ 284M[6]
(6) rate impact (or projected rate impact) for the project	Since 2005, Alabama Power Company has spent in excess of $2.2 billion on plant placed in service at Plants Barry (Unit 5 SCR and Scrubber), Gaston (Unit 5 SCR and Scrubber), Gorgas (Units 8-10 Scrubbers), and Miller (Units 1-4 SCRs and Scrubbers) in order to comply with various environmental mandates. The Company's retail rates, approved by the Alabama PSC, provide for adjustments that allow for the recovery of retail costs associated with environmental laws, regulations and other such mandates. The environmental rate mechanism is based on forward looking information and provides for the recovery of these costs pursuant to a factor that is calculated annually. Since January 2005, the Company's retail rates associated with environmental compliance have increased approximately 9.5%.						
(7) the degree to which project would help plant or unit achieve the proposed emissions limits of the utility air toxics rule	These scrubber projects would help the respective units reduce some of the emissions regulated in the proposed MACT Rule but will not by themselves, or even in combination with other controls already installed on some of the units resulting in co-benefit emission reductions, achieve compliance with all of the limits for all pollutants contained in the proposed rule. Significant investment in additional controls (likely baghouses), as well as additional continuous emission monitoring equipment will be required for all of these units. This investment is in addition to the significant capital shown above that has already been invested in these units.						

[1] The Gorgas 8-10 scrubber project involved a single scrubber vessel installed on 3 units. All other projects are individual scrubber vessels installed on single units.

[2] Engineering dates begin with conceptual planning phase and end with completion of detailed design.

[3] Air construction permitting only: beginning of application preparation to issuance of construction permit

[4] Construction dates begin with field mobilization and end with operation of scrubber equipment.

[5] Jobs created represent the contractor man-hours expended on the job divided by 2080 man-hours to give representative "man-years".

[6] Total capital costs include total installed cost.

7. **For Southern plants affected by the utility air toxics rule, please provide a list of plants and pollution control installations that will be required for compliance. Please list the plant, the type of pollution control equipment Southern intends to install, estimated capital cost, and whether Southern has begun design and engineering of any type.**

In recent years Southern has invested over $8.0 billion in environmental controls and could spend an additional $4.1 billion over the next three years to comply with current, revised or new rules. This previous investment includes scrubbers installed and operating on 24 units, SCRs installed and operating on 16 units, and baghouses installed and operating on 4 units. Despite this significant capital investment in our fleet, additional controls are likely to be required in the future.

The proposed MACT rule would impact all of Southern's coal- and oil-fired generation – over 20,000 MW of generation. Southern's compliance strategy planning process is a continuously on-going process that considers all of the applicable or potentially applicable rules that are under development when deciding whether to install environmental upgrades, switch fuels or retire and replace generating units. Selection between these options is based upon a financial assessment of which option ultimately is expected to be the most reasonable, cost effective alternative for our customers. The assessment also incorporates variations in the operating environments (such as fuel prices) that may affect the decision on particular units. Specific compliance strategies, including types of additional pollution controls and estimates of capital costs are uncertain at this time and will depend on the emission limits and other requirements of the final MACT rule and all of the other rules expected to affect utility sources. Southern's ultimate compliance strategy will likely include a combination of installation of additional environmental controls, conversion of some units to natural gas, and retirement and replacement of generation. When making these decisions, all the current and future requirements must be included, but the decision will be triggered by the first requirement. Preliminary engineering, aimed at attempting to streamline some control project implementation has begun. This is in addition to the engineering work begun for the Plant Daniel scrubber project (shown above). However, despite this early effort, some projects will not be completed by the unrealistic deadline imposed by the proposed Utility MACT rule.

Our experience tells us that the installation of multiple controls at multiple facilities cannot occur in three years. Even if we are able to obtain a one year extension for some units, there is not enough time to design and construct all of the controls. Furthermore, our experience tells us, the more compressed the time schedule, the higher the impact on the feasibility and cost of the projects and greater the impact on electricity rates.

Our technology experts believe that the proposed MACT rule would require virtually every coal plant to operate scrubbers and most likely baghouses to meet the proposed emissions limits. Even if we are able to obtain a one year extension, compressing the work into a 4 year schedule will escalate the required cost significantly and unnecessarily, which will directly impact our customers.

Plant Scherer near Macon, Georgia is a good example of what it can take to install multiple controls at a single facility. We are in the midst of an ambitious environmental retrofit program that will equip each of the 4 units with SCRs, scrubbers, and baghouses, in addition to the existing electrostatic precipitators. Upon completion, this site will be one of the best controlled coal power plants in the country.

The baghouses alone for the four Scherer units took approximately 5 years, start to finish, including design, installation, and startup. The cost was $558M. Retrofitting an existing facility that was not designed for the equipment presents unique challenges that put pressures on cost and schedule. As a simple example, at Plant Scherer, the Unit 3 baghouse had to be constructed nearly 1,200 feet from the electrostatic precipitator because there simply was not enough space to install the equipment any closer. To span that distance, the ductwork alone costs about $22,000 per foot, totaling tens of millions of dollars. With the addition of scrubbers and SCRs, the design, engineering, and construction program for all of the environmental controls at Scherer will take almost 10 years. We are not taking our time building these controls. This is a very aggressive schedule that involves nearly 2,000 workers, 60,000 tons of steel, and hits nearly every usable space onsite. Throughout all of this construction work, the plant also has to operate. Our experience tells us that to complete multiple control installations requires careful planning and execution and, importantly, time.

Finally, our experience tells us that requiring an entire industry to install controls within a compressed time frame will result in material and labor shortages and dramatically escalating costs that EPA has not accounted for in its proposed rule.

The Honorable Charles A. Gonzalez

1. **Should there be a neutral third party designated to review the science and cost estimates put forth by both EPA and industry stakeholders with regard to proposed rulemakings? If so, who should that third party be and why?**

It is uncertain which parts of science and costs this question is referencing. If "science" is interpreted to be mercury health science, a neutral third-party review could be provided by Dr. Gary Myers at the University of Rochester [who did the Seychelles mercury study research].

If "cost" is meant to be control technology cost estimates, then such estimates could be verified by designees such as engineering and construction firms provided that the scope of each project(s) is clear and consistent. However, the best source of information will still remain the utilities based on their actual project experience.

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[i] NERC (October 2010) *2010 Special Reliability Scenario Assessment: Resource Adequacy Impacts of Potential U.S. Environmental Regulations*

[ii] Bernstein Research (October 2010) *U.S. Utilities: Coal-Fired Generation Is Squeezed in the Vice of EPA Regulation; Who Wins and Who Loses?*

[iii] *Eggers, D., et al. (September 23, 2010). Growth From Subtraction: Impact of EPA Rules on Power Markets. Credit Suisse Equity Research*

CRA Charles River Associates

Memorandum

To: Charles Rossmann, Southern Company

From: Scott Bloomberg, Anne Smith and Paul Bernstein

Date: March 28, 2011

Subject: Modeling Assumptions for Reference and Scenario 2 Analysis

The following outlines the major assumptions we included in our analysis of the Reference Case and Scenario 2. In many instances, our assumptions were informed by those used by EEI in its report, "Potential Impacts of Environmental Regulation on the U.S. Generation Fleet."[1] These assumptions were used in the Charles River Associates (CRA) analysis using our proprietary MRN-NEEM modeling system. The model years included as part of the analysis were 2010 (no actions were required to be taken in 2010 since it is now 2011), and then every five years through 2050. The every five years approach was used because we utilized the MRN-NEEM model, instead of just NEEM.

Reference Case Assumptions

Where reasonable CRA's assumptions were the same as those used in the EEI analysis, in other instances CRA assumptions were used because they were quite similar to those used by EEI (and EEI's assumptions could not be easily implemented). The following table contains a list of key variables and the assumptions used.

Variable	**Assumption**	**Source**
Natural Gas Prices	AEO 2011 Henry Hub prices	AEO 2011
Electricity Demand Growth	AEO 2010 growth figures	EEI report, p. 29
Coal Prices	CRA supply curves	CRA analysis of publicly-available information
New Build Costs and Characteristics	Costs and characteristics used by EEI	EEI report, p. 32

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[1] Analysis prepared by ICF International, January 2011.

Retrofit Costs and Characteristics	Costs and characteristics used by EEI (includes capital, FOM, VOM, removal rates, derates[2] and financing	EEI report, pp. 33-38
Planned Coal Retirements	9.8 GW of planned coal retirements	Energy Velocity, Dec. 2010 query
Planned Additions	37.7 GW in U.S.	Energy Velocity, Dec. 2010 query
Planned Retrofits	42.3 GW of FGD/SCR, 45.9 GW of ACI	Energy Velocity, Dec. 2010 query (note: EEI's significantly higher numbers include 2010 retrofits that are included as existing retrofits in CRA's analysis)
Nuclear Build Limits and Forced Additions	Forced 5.5 GW of new nuclear additions, 45 new units allowed by 2030 (1.1 GW each)	EEI report, p. 40 (specific units provided by C. Rossmann)
Environmental Rules	Inclusion of CAIR, State Hg rules and State RPS	EEI report, p. 42

Scenario 2 Assumptions

The following table contains a list of the key assumptions used in modeling Scenario 2.

Variable	Assumption	Source
Natural Gas Prices	Changes in prices determined endogenously in MRN-NEEM model based on changes in economy-wide natural gas demand	NA
Electricity Demand Growth	Changes in electricity determined endogenously in MRN-NEEM model based on changes in delivered electricity prices	EEI report, p. 29
Coal Prices	CRA supply curves	CRA analysis of publicly-available information

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[2] We were not able to model derates associated with cooling tower additions.

Environmental – "Air Base Case"	All coal units required to have FGD, ACI and FF by 2015; CATR using EPA's Preferred Approach; SCRs required on all "Eastern" units by 2018 (modeled as by 2020); "Western" coal units required to install SCR in 2018 (modeled as by 2020) if cost per ton removed is less than $5,000.	EEI report, p. 43
Environmental – "Ash Base Case"	Compliance with ash requirements in 2017 and 2019 (modeled as by 2020), including conversion to dry ash handling, conversion to dry bottom ash handling, and install new wastewater treatment capability	EEI report, p. 45
Environmental – "Base Water Case"	Cooling towers required on approximately 400 fossil and nuclear facilities by 2022 and 2027, respectively (modeled as 2020 and 2025, respectively); costs applied as an adder on variable O&M	Specification of units with requirement provided by C. Rossmann; conversion of $/gallon-per-minute to $/kW provided by C. Rossmann (533 gpm for fossil and 712 gpm for nuclear); converted to $/MWh based on assumed capacity factor for coal and nuclear, respectively
CO_2 Policy	$25/short ton (in 2008$) in 2017, rising at 5% in real dollars; $25/ton price discounted by 5% for two years to set price beginning in 2015; price applied on electric, energy-intensive and refining sectors	EEI report, p. 50 (EEI report did not specify sectors on which CO2 policy would apply)

Results

Results spreadsheets were sent that included the following results:

- Wholesale and delivered electricity prices
- Electricity demand
- Natural gas consumption
- Wellhead natural gas prices
- Losses in household purchasing power (increased cost per household)
- GDP
- Consumption
- Economy-wide and electric sector CO_2 emissions
- Job equivalents

- Coal unit retirements
- Electric sector capital expenditures on retrofits and new capacity
- New capacity additions (by type of generation)
- Coal retrofits (FGD, SCR, ACI/FF)

Results were provided for the following cases (case shortname):

- Reference Case (bau)
- Scenario 2, with CO_2 policy only applied to electric sector (ScnA)
- Scenario 2, with CO_2 policy applied to electric, energy-intensive and refining sectors (ScnB)
- Scenario 2, without any CO2 policy (NoTax)
- Reference Case with higher natural gas prices (bau_HighGas) – Henry Hub gas prices increased by $1/MMBtu starting in 2015 and applied to all subsequent years
- Scenario 2, with CO_2 policy applied to electric, energy-intensive and refining sectors, based on the higher reference case natural gas prices (HighGas)
- Scenario 2, with CO_2 policy applied to electric, energy-intensive and refining sectors, and with new combined cycle cumulative build limits of 44 GW by 2015 and 104 GW by 2020 and 60 GW additional every five years (CC_Limits_44)
- Scenario 2, with CO_2 policy applied to electric, energy-intensive and refining sectors, and with new combined cycle cumulative build limits of 60 GW by 2015 and 60 GW additional every five years (CC_Limits_60)

Economic impacts of environmental requirements

Estimates for Scenario 2 studied by EEI* (Air, Ash, Water and CO_2)

During the next few years several new, stringent environmental requirements will take effect causing costly changes in electricity production. These changes will reduce employment income, raise the price of electricity and reduce household buying power.

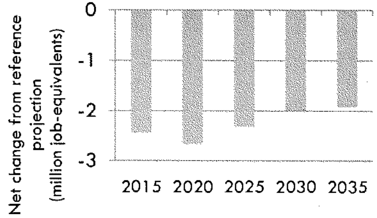
Reduced worker income. US employment income is estimated to drop by an amount equivalent to the earnings of about 2-2.5 million full-time workers. This estimate includes an estimated increase in "green" employment income equivalent to about 0.2-1 million full-time workers in the years through 2025. (The estimated green increases are minimal thereafter.) Without these green increases, the estimated reduction in worker income would be 2-3.5 million. Green employment includes environmental retrofitting, new power plant construction and energy efficiency improvements.

Higher electricity price. Retail electricity price is estimated to increase by 10-20% to cover the costs of complying with the new environmental requirements. Costs include installing emission control equipment, constructing new generating units, shifting more generation away from less-expensive plants to more-expensive ones and retiring existing coal units.

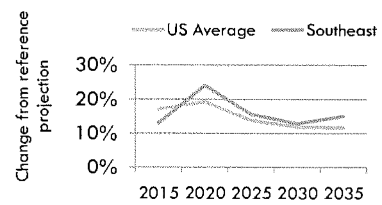
Lost household buying power. The average US household is estimated to lose buying power of \$400-\$500 per year. This reflects higher prices for energy-intensive goods and natural gas and reduced household income due to both reduced employment income and reduced investment income.

Reduced Worker Income

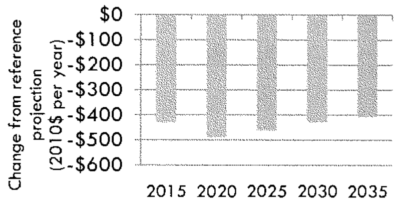
(stated as job-equivalents)**



Higher Retail Electricity Prices



Lost Household Buying Power



Source: Analysis conducted by A. Smith, S. Bloomberg, P. Bernstein, M. Yuan and D. Montgomery of Charles River Associates for Southern Company, March, 2011. The analysis used CRA's MRN-NEEM model of the US energy economy. The analysis adopted the same assumptions as the EEI analysis* except for natural gas for which it adopted a lower-price view of than EEI and coal for which it adopted a higher-price view than EEI. This analysis focused on EEI's Scenario 2 which includes air, water, ash requirements and a \$25+ per ton CO_2 fee. The results were similar across sensitivity cases.

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* Edison Electric Institute, "Potential Impacts of Environmental Regulation on the US Generation Fleet," January, 2011.

** Estimated net *job-equivalent* changes are the estimated net change in aggregate employment income divided by wage income per full-time worker. This net change recognizes that there may be increases in some areas and decreases in others.

Responses from Anthony F. Earley, Jr., Executive Chairman, DTE Energy to Chairman Ed Whitfield, Subcommittee on Energy and Power, Regarding May 20, 2011 Request

Questions from the Honorable Henry A. Waxman

1. In your response to questions at the hearing you claimed that EPA rules would lead to 50 to 75 GW of coal fired generation retirements.

a. Please identify the sources or studies on which you rely for this claim.

. There are a number of studies that suggest that the number of early retirements would be more than EPA's projections of early retirements, due largely to EPA's assumptions regarding technologies to meet the EPA rules. The analysis upon which I based the claim for 50 to 75 GW of coal fired generation retirements is the "*Potential Impacts of Environmental Regulation on the U.S. Generation Fleet*," an Edison Electric Institute analysis prepared by ICF International, and submitted to EPA Administrator Jackson on January 28, 2011. This analysis was performed as a collaborative effort among EEI member companies.

b. For each study, for each regulatory requirement analyzed as driving generation retirements, please identify whether the most recent version of the regulatory requirement proposed or finalized by EPA differs from the version of the regulatory requirement modeled in the analysis in terms of the stringency of emissions limits, the technologies required to comply, the inclusion or exclusion of flexible approaches, timing of the compliance requirement, or other material differences. Also identify any regulatory requirements included in the analysis for which EPA has not yet issued a proposal.

. The EEI analysis summarizes nine modeling runs of various base and alternate regulatory scenarios for air quality, water, coal ash, and greenhouse gases (CO_2) for comparison to a reference case. The reference case includes existing "on the books" state and federal regulations including the Clean Air Interstate Rule (CAIR), state-based mercury regulations, and state renewable energy standards. The modeling was completed before the proposed rules for the Electric Generating Unit (EGU) Maximum Achievable Control Technology (MACT) standard and the proposed rule for Cooling Water Intake Structures under Section 316(b) of the Clean Water Act were issued by EPA in March 2011. The purpose of the modeling exercise was to evaluate the potential impacts for unit retirements, capacity additions, pollution control installation, and capital expenditures on national and regional level scales for various regulatory scenarios. Descriptions of each of the scenario cases are provided in Appendix B of the EEI Analysis.

In the absence of the proposed rules for the EGU MACT and 316(b) Cooling Water Structures, and without knowing the final outcome of the Transport Rule and Coal Combustion Residual Rule, expected levels of stringency, technology requirements, timing, etc. were varied in the modeling runs to evaluate a range of impacts. For example, Run 3 provided the flexibility for units 200 MW or less to install dry sorbent injection (DSI) technology instead of a scrubber to comply with the MACT Rule, and the NO_X cap for the Eastern U.S. is reduced to approximate caps included in Senator Carper's proposed utility legislation. Run 4 limited the requirements for cooling towers to power plants with once-through cooling with an intake flow rate greater than 125 million gallons per day. Run 8 considered ash being regulated as a hazardous waste under Subtitle C of the Coal Combustion Residuals rules. Additional modeling runs varied the cost to emit CO_2 and the impacts of higher natural gas prices as an alternate fuel source for electric generation. The nine modeling runs were intended to provide a range of possible impacts to cover the range of uncertain limits and standards expected in the final EPA rules. Thus, my response was 50-75 GW of coal fired generation retirements rather than a single number.

c. For each regulatory requirement analyzed, please provide the assumptions regarding the content of the requirement used in the analysis. For example, for the 316(b) water rule, provide the expected technology requirements and timing relevant to the projected retirements. For any regulatory requirement that has not yet been proposed by EPA, please provide the basis for the assumptions regarding the content of the requirement used in the analysis, as well as identifying those assumptions.

The assumptions for each modeling run are described in Appendix B of the EEI Analysis. For Scenario 1 (Run 2) that models the base case, the assumptions are as follows:

Base Air Case + Ash (Subtitle D) + Water

- MACT compliance for all HAPs requires all coal units to be controlled with a scrubber (wet or dry), activated carbon injection (ACI) and a baghouse/fabric filter. Oil gas steam units that burn oil only have to install an electrostatic precipitator (ESP). Oil gas steam units that are dual fuel capable are assumed to switch to gas to comply. Compliance is required by 2015 to satisfy the HAPs MACT Consent Decree timeline.
- No additional controls are required for SO_2-specific compliance.
- Eastern NO_X compliance is modeled on EPA's preferred option for the proposed Transport Rule with trading allowed up to the variability limits through 2017. Starting in 2018, all units required to install SCRs to be deemed "well controlled" to meet future NOX requirements.
- Western NO_X compliance modeled to assume that for BART compliance that SCRs are installed on all units where the cost to control NO_X is $5,000/ton removed or less starting in 2018. Prior to 2018, only announced and committed SCRs as a result of completed BART determinations are required.
- All units with wet fly ash disposal and/or wet bottom ash disposal are required to convert to dry handling, and install a landfill and wastewater treatment facility. Assume the final rule promulgation occurs in 2012. Under Subtitle D, plants will have 5 years (2017) to stop using active ponds and 7 years (2019) to close all ponds.
- All fossil and nuclear facilities that have at least one once-through cooling unit are required to install cooling towers. Fossil units are allowed 10 years to achieve compliance. Nuclear units are

allowed at least 15 years or to their current license expiration. To emulate this timeline, EEI has assumed compliance no later than 2022 for fossil units and no later than 2027 for nuclear units.

Scenario 2 adds a $25/ton price to the emissions of CO_2. The remaining runs vary the price of carbon, the price of natural gas, and the assumptions above to assess impacts.

d. In light of the differences between the modeled versions of the regulatory requirements and EPA's most recent actual proposed or final requirements, how relevant are the analytical conclusions of the study or studies? If the analysis were updated to reflect the rules as actually proposed or finalized by EPA, do you believe it would still project 50 to 70 GW of retirements? If yes, what is the basis for this view?

The March 2011 proposed rules for the EGU MACT and 316(b) Cooling Water Structures do not significantly change the assumptions or alternatives that were evaluated in the EEI analysis. As I stated in my testimony, there is not enough time under the current rulemaking time frame to fully comment on the proposed rules. Full scale technology evaluations need to be conducted on a unit-specific basis in order to evaluate the most cost effective control options to meet the emission or technology standards. These evaluations cannot be performed effectively in the time allotted by EPA to comment on the proposed rules. Until further technology evaluations are performed, the assumptions and results of the EEI analysis remain relevant.

2. Of the 50 to 70 GW of projected retirements, identify how many GW of retirements have already been announced. Of the remainder, to what degree are the projected retirements dependent on the price of natural gas and the remaining useful life of the facilities?

The EEI analysis indicates that 6 GW of planned coal retirements are expected by 2015. These planned retirements were "hard-wired" into each of the modeling runs. These planned retirements represent firm retirements based on regulatory filings, press releases, and EEI member feedback. The report notes that subsequent retirement announcements (post December 2010) have been made that were not included in the model.

Two runs in the EEI analysis modeled the impact of higher gas prices, and these runs had the lowest number of coal plant retirements. This is not unexpected, because higher gas prices lead to higher power prices and therefore higher margins. Coal units become more profitable with higher margins and are therefore better able to incur the capital costs for installation of technologies necessary to comply with the EPA rules.

3. **In your responses to questions at the hearing you claimed that the utility air toxics rule would lead to 25% price increases for DTE Company customers. Please provide the cost support for this statement, including the capital and O&M costs assumed, the amortization period, the cost breakdown by rate class, the baseline rate assumptions, and the calculation of the 25% price increase.**

My answer was in reference to the potential rate impact of the full set of proposed EPA rules, not the utility toxics rule in isolation. When evaluating the economics of retrofitting control equipment on individual units, we must evaluate all of the potential retrofits as a whole. If a relatively inexpensive retrofit was economical on a unit, but an additional costly retrofit was required on that unit for a separate regulation, then we would not build the smaller retrofit if the more costly retrofit made the unit uneconomical.

On a national basis CRA/ICF developed modeling in early 2011 that estimated retail electricity prices to increase by 10 to 20% to cover the costs of complying with the new environmental requirements. Costs include installing emission control equipment, constructing new generating units, shifting more generation away from less-expensive plants to more-expensive ones and retiring existing coal generation. Localized impacts in certain areas that lack ready alternatives at reasonable rates, especially in the coal-dependent Midwest, create price increases of 20-25%.

We are still in the process of analyzing and reviewing the impacts of the proposed rules on DTE costs and rates, but the current analysis indicates a similar rate increase forecast for Detroit Edison customers approaching 25%. This analysis assumes Flue Gas Desufurization (FGD) is required for compliance with the air toxics rule as proposed. [Detroit Edison will conduct testing of potentially less costly compliance technologies, but this will require time and will be expensive. Based on what we know today, we must assume FGDs are required for compliance. If testing shows a less capital intensive, but as yet very little used, technology like Dry Sorbent Injection (DSI) can assure compliance, our analysis may change somewhat. This is a key reason for our insistence that more time is required for analysis of the existing rule, providing EPA comments, and implementation of a final rule.] Proposed 316(b) rules are assumed to require cooling towers on Monroe Power Plant, and regulating coal combustion byproducts (CCB) as either hazardous or non-hazardous wastes is assumed. As a result of these costs, early retirement is forced on all coal-fired units except for Belle River Power Plant and Monroe Power Plant.

Detroit Edison then requires 13,500 GWh of replacement power as a result of the early retired units. This analysis uses forecasted energy prices from recent IHS CERA analysis of the same regulatory impacts to determine the replacement energy and capacity cost. This scenario results in a 24% rate increase.

4. **For the utility air toxics rule, please provide a list of plants and projects that will be required for compliance. Please list the plant, the type of pollution control equipment you intend to install, estimated capital cost, and whether you have begun design and engineering of any type.**

Detroit Edison has 21 boilers that are subject to the utility air toxics rule. Retrofits would require Flue Gas Desufurization (FGD) equipment on several units along with activated carbon injection (ACI) for mercury control. Application of ACI would necessitate additional particulate control, including enhancement of existing electrostatic precipitators (ESP) or addition of fabric filters (FF or Baghouse), on several units.

EPA's decision to use HCl as a surrogate for acid gases opens the possibility of less capital-intensive technologies, such as dry sorbent injection (DSI), instead of FGD. Testing of these technologies and various sorbents will be conducted in 2011 to develop a better understanding of capabilities within the diverse Detroit Edison portfolio of boiler and fuel types. With the compliance time requirement set at 3 years, and the limited possibility of an additional year for some sources, we cannot wait until the rules are final to conduct this important testing. For units that will require FGD installations, the time available is extremely short.

Harbor Beach is a 103MW coal-fired boiler burning bituminous coal. It is not expected that required reductions on this boiler could be achieved with DSI. This boiler would require FGD for acid gas reduction (estimated ($100M), along with ACI and FF installation (estimated $30M) for mercury and other toxic metals reduction. We have not begun design and engineering on this equipment.

Greenwood is a 785MW boiler that fires a combination of oil and natural gas. The requirements of the utility air toxics rule will result in Greenwood becoming a natural gas-fired boiler only, resulting in a loss of generating capacity.

Belle River Power Plant consists of two 635MW boilers firing subbituminous coal. It is expected that these units will be potential candidates to achieve the required acid gas reductions using DSI (estimated $30M). If testing demonstrates DSI cannot achieve the required reductions, installation of FGD (estimated $525M) would be required. Addition of ACI for mercury reduction (estimated $6.5M) will be required in either case. ACI and DSI would add an estimated annual sorbent cost of $70M to operating Belle River Power Plant. An engineering study has begun to understand the implications of adding post combustion controls to the back of these two units

St. Clair Power Plant includes six coal-fired boilers with a total net summertime capacity of 1,365MW. Units 1-4 and 6 are potential candidates for DSI (estimated $30M with annual sorbent costs of $40M). Unit 7 will be investigated for the potential of DSI with a required FF. If FGD is required at St. Clair Power Plant, Units 1-4 would likely be designed for a single absorber (estimated $275M) with units 6 and 7 controlled by another single absorber (estimated $325M). ACI (estimated $7M capital and $34M annual O&M) will also be required for mercury reduction. Design and engineering have not begun on these units, except for an engineering study to investigate FF installation on Unit 7.

River Rouge Power Plant has two affected units with 523MW summertime capability. These boilers burn a blend of bituminous and subbituminous coals and are not expected to achieve required acid gas reductions with DSI, although testing will be conducted to evaluate this capability. These units will also be testing for DSI capability with alternate coal-types, which would result in decreased capability of the units. If DSI cannot meet the reduction requirements on these units, FGD (estimated $225M) would be required. ACI ($3M capital +$25M annual O&M) would be required in either case for mercury control. We have not begun design and engineering on this equipment.

Trenton Channel Power Plant consists of 5 boilers with a total capability of 730MW. These boilers burn a blend of bituminous and subbituminous coals and are not expected to achieve required acid gas reductions with DSI, although testing will be conducted to test this capability. These units will also be testing for DSI capability with alternate coal-types, which would result in decreased capability of the units. DSI would require FF on these units for particulate control. If DSI cannot meet the reduction requirements on these units, FGD (estimated $350M) would be required. ACI ($4M capital +$20M annual O&M) plus FF ($125M) would be required in either case for mercury control. We have not begun design and engineering on this equipment, although the St. Clair FF engineering study is useful for analyzing Trenton Channel U9A FF capability and implications.

Monroe Power Plant has 4 boilers with 3,102MW summertime capability. All four boilers will be retrofitted with FGD and SCR ($2.1B) by 2015, and are expected to be compliant with the requirements of the utility air toxics rule.

In addition to evaluating which technologies will ultimately be needed to assure compliance with the new regulations, economic evaluations will determine if installation of equipment, retirement with installation of new generation, or purchase from the market minimizes the cost to our customers.

Questions from the Honorable Charles A. Gonzalez

1. **Should there be a neutral third party designated to review the science and cost estimates put forth by both EPA and industry stakeholders with regard to proposed rulemakings? If so, who should that third party be and why?**

We would strongly recommend designation of the Electric Power Research Institute (EPRI) to review the science and cost estimates put forth by EPA and industry stakeholders with regard to proposed rulemakings. Despite its name and close collaboration with the electric utility industry, EPRI's role as an independent, nonprofit organization is to conduct research and development relating to the generation, delivery and use of electricity *for the benefit of the public*. EPRI scientists and engineers, as well as experts from academia and industry, work on addressing challenges in electricity, including reliability, efficiency, health, safety and the environment. EPRI's clear role is technical evaluation of various technologies applicable to the industry and not advocacy efforts.

EPRI has played an instrumental role in the review of data collected by electric utilities in response to EPA's Information Collection Request (ICR) to support development of the EGU MACT rulemaking. EPRI undertook an extensive effort to obtain and review ICR test reports and data files before utilities submitted them to the EPA. EPRI's data quality reviews found numerous data quality concerns that could have an adverse effect on the accuracy or usability of the ICR data. EPRI is also very active in environmental research activities regarding fish protection and the effectiveness of cooling water intake structures, climate change policy, and coal combustion product management research.

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June 3, 2011

Representative Edward Whitfield
Chairman, Subcommittee on Energy and Power
Committee on Energy and Commerce
House of Representatives
2125 Rayburn House Office Building
Washington, DC 20515-6115

Dear Representative Whitfield,

Thank you for the additional questions for the record from members of the Subcommittee on Energy and Power related to my testimony at the hearing entitled "The American Energy Initiative" on April 15, 2011. Please accept my responses to each question below:

The Honorable Henry A. Waxman

1. **Hearing testimony suggested that 80 to 100 GWs of existing coal-fired capacity would be required to install scrubbers to comply with EPA's proposed emission limits. Do you agree that a significant number of coal-fired power plants will need to install scrubbers?**
   I disagree that a significant number of coal-fired power plants will need to install scrubbers as a result of the Utility Toxics Rule. As I indicated in my testimony, roughly 60 percent or close to 200 gigawatts (GW) of the nation's coal capacity has already been retrofit with scrubbers or is close to completing the installation of controls. Among large coal-fired generating units – primarily baseload coal units greater than 400 MW—more than 70 percent have scrubbers installed. Of the 320 GW of existing coal-fired power plants, 191 GW have already installed or are in the process of installing scrubbers. Installing scrubbers at 80 to 100 GW of existing coal-fired capacity would imply that all or virtually all coal capacity would be retrofit. This would not be a reasonable assumption. Companies have already announced 13 GWs of coal plant retirements, and analysts project that approximately 67 GW are likely to install dry sorbent injection (DSI) rather than a scrubber in order to comply with the Toxics Rule. Of the remaining 49 GW of coal fired capacity, about 34 GW could potentially take advantage the averaging provisions under the proposed Toxics Rule, which allows companies to average a unit's emissions across all of the boilers at a facility avoiding the need for a scrubber. This leaves only about 15 GW of coal units that may need to be retrofit with a scrubber or retired as a direct result of the Utility Toxics Rule. (See Slide No. 1 in the attached appendix for additional information).

2. **During the hearing, statements were made that 25 to 80 GW of coal-fired capacity would be retired. Please provide your perspective on these estimates. What are the primary drivers of those retirement estimates?**
   The electric industry and investor community generally expect a more modest level of coal capacity retirements. The median projection is 32 GW of retirements nationwide. Slide No. 2 in the attached appendix includes a list of recent analyst reports and their projected coal capacity retirement estimates. Also, the U.S. Department of Energy projected relatively modest coal plant retirements under EPA's air rules in its Annual Energy Outlook 2011. Even a scenario that forces SCRs and

scrubbers on all coal plants, which we do not expect to be the case, results in only about 10 GW of coal plant retirements above reference case levels, according to DOE. We would emphasize that many of these reports were completed before EPA even issued the proposed Utility Toxics Rule, and in several cases, reflect conservative assumptions in terms of the pollution control expenditures that will be required to comply with the rule.

Additionally, the Analysis Group recently released a peer review analysis of an EEI report that was referenced at the hearing. In one of its more aggressive scenarios, the report projected 70 to 80 GWs of coal plant retirements. The Analysis Group's peer review evaluates those retirement projections in light of the actual proposed Utility Toxics Rule and cooling water intake regulations under 316(b) of the Clean Water Act, both of which EPA released in March 2011, two months after EEI issued its report. The peer review concludes that the report was based upon "worst-case assumptions" that have not materialized and upon climate change legislation never enacted into law. The study goes on to find that approximately one half of the total retirements predicted by the report result from low natural gas prices, not EPA regulations. I have attached a copy of the Analysis Group's peer review analysis, and included additional information in Slide No.3 in the attached appendix.

3. **What are the regional capacity margins for each of the regions in the United States, and are there any specific regions of concern for reliability? If so, what frameworks and regulatory tools currently exist to address such concerns?**

The U.S. bulk electric system is divided into eight reliability regions. Analysis by the North American Electric Reliability Corporation (NERC) indicates that all NERC regions are estimated to have reserve margins in 2014 that are well in excess of the minimum reserve requirements. Slide No. 4 in the attached appendix lists the capacity margins for each region.

The RFC and SERC regions, which both contain significant coal capacity, are expected to have reserve margins of 34 percent and 29 percent, respectively. These regions, therefore, could retire significant amounts of existing coal capacity and still maintain the 15 percent NERC reserve margin targets. (See Slide No. 5 in attached appendix.)

While adequate reserve margins exist at the aggregate regional level, power plant retirements may nevertheless trigger localized reliability concerns in some cases. In such cases, the Clean Air Act (CAA), Federal Power Act (FPA), and other statutes provide EPA, DOE, FERC, and the U.S. President an array of tools to moderate, when and where necessary, potential impacts on electric system reliability. For example, EPA can grant time extensions for power plants to install pollution control equipment on a case-by-case basis under the Clean Air Act. EPA and the Department of Energy have the authority to enter into administrative orders of consent or consent decrees with power plants that allow them to run under specific and limited circumstances to maintain reliability. Additionally, the Department of Energy can override Clean Air Act requirements under section 202(c) of the Federal Power Act in limited emergency circumstances, and the President has the authority under the Clean Air Act to extend deadlines in the Utility Toxics Rule if the technology is not available and there is a national security interest to do so. (See Slide No. 6 in attached appendix.)

4. **Do EPA's proposed emission limits in the utility air toxics rule reflect the performance of any existing plants? If so, please provide a list of the plants that already achieve all of EPA's proposed utility air toxics emission limits.**
   Yes, based on the data reported to EPA in Part III of the Information Collection Request (ICR) for the Utility Toxics Rule and company statements, there are at least 33 units already meeting each of EPA's proposed emission limits in the Utility Toxics Rule. Note that this is a conservative figure based on a sampling of coal-fired generating units. I have included the list of such units in Slide No. 7 in the attached appendix.

5. **You indicated in your testimony that the electric sector is well positioned to comply with the utility air toxics rule. Please provide any additional information you have to support that conclusion.**
   Slides Nos. 8-11 illustrate that the electric sector is well positioned to comply with the Utility Toxics Rule. Among coal-fired units that submitted emission data under EPA's most recent ICR, nearly 60 percent of units are compliant with EPA's proposed limit for mercury; 73 percent of units are compliant with EPA's proposed limit for HCl; and almost 70 percent of units are compliant with EPA's proposed limit for PM. Slide No. 10 also provides additional information on dry sorbent injection – a technology that reduces SO_2 and other acid gases. Relative to a scrubber, DSI requires much lower capital costs. Generally, DSI will be considered for coal units burning low sulfur coal. Other factors that will drive the deployment of DSI include unit size, percentage reduction of emissions required, plant economics, and site specific characteristics. Several companies have already installed, or are in the process of installing, DSI technology including NRG, Duke, and GenOn.

   Further, the Clean Air Act provides the necessary time for companies to comply with the proposed emission limits. As I testified during the hearing, several companies have already installed, or are in the process of installing advanced controls, that they anticipate will allow them to comply with the Utility Toxics Rule. Constellation Energy recently installed a major air quality control system at its Brandon Shores facility in Maryland. The construction included a Flue Gas Desulfurization system – commonly called a scrubber, plus a Pulse Jet Fabric Filter – commonly called a baghouse – with sorbent injection. These are two of the technologies that companies may install in response to the Toxics Rule with the wet scrubber being the most capital- and time-intensive technology. Construction began in June 2007 and was completed in September of 2009.[1] The construction phase was completed in approximately 26 months. The three year period that was referenced during the hearing on April 1Sth was based on a press release on the Brandon Shores project, and included the testing and tie-in process as well as construction phase.

   The planning and permitting process that Constellation undertook started before the construction commenced in June 2007. Anticipating future environmental standards, Constellation had begun studies and conceptualization of the project prior to the passage of Maryland's Healthy Air Act (HAA) in April 2006. The engineering, design, contracting, procurement, planning, and layout commenced while the regulations were being finalized with the Maryland Department of the Environment (i.e., prior to mid-2007). Thus, the total time from the initial planning to the completion of construction was under four years (January 2006 through September 2009).

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[1] Testimony of Paul J. Allen, at the Joint Hearing of the U.S. Senate Subcommittees on Clean Air and Nuclear Safety, Environment and Public Works, and Green Jobs and the New Economy, March 17, 2011 (available at: http://epw.senate.gov/public/index.cfm?FuseAction=Files.View&FileStore_id=f5f0e0d2-a7b7-4e33-90d3-149d28645e2e).

The planning that Constellation undertook prior to the rules being final is a step that will be important for companies to undertake now in anticipation of a final Utility Toxics Rule in November. Similarly, NextEra Energy, also a member of the Clean Energy Group, expected that it would need to install Electrostatic Precipitators (ESPs) on several of its oil-fired units to comply with the Utility Toxics Rule. Prior to the proposed Rule being released, NextEra initiated the approval process with the Florida Public Service Commission (PSC). The PSC approved NextEra's request, allowing NextEra to begin installing the ESPs based on the proposed Utility Toxics Rule.[2]

While companies will generally not make significant capital expenditures in advance of a final rule, they can begin planning and engineering to ensure that they are in a position to comply within three years of EPA issuing a final rule. The associated costs that can be undertaken before the rule is final are not onerous, and prudent generators can expend these funds as part of developing an integrated environmental compliance strategy. This advance planning will also allow companies to better control costs, establish a cost-effective schedule for constructing and installing any necessary control technologies, and ensure companies are well positioned to comply with the Utility Toxics Rule.

6. **Please provide your views on the NERC reliability analysis for the southeast.**
NERC's most recent Long-Term Reliability Assessment projects that the U.S. Southeast (the SERC reliability region) will have a 29 percent capacity reserve margin in 2014. This is well above NERC's reference level for the region, suggesting that the region can absorb the retirement of older, less efficient generating units in the region.

Additionally, in July 2010, SERC's Reliability Review Subcommittee completed its 32nd annual review of sub-regional expansion and reliability plans in the Southeast U.S.[3] The report suggests that the Southeast region would be well-positioned to accommodate potential future capacity retirements:

- Almost 21 GW of natural gas-fired and nuclear capacity is projected to come online between 2010 and 2019 in the region.
    - Utilities in the Southeast are planning ahead and pursuing a low emitting generating portfolio.
- The SERC region has significant uncommitted generating capacity (i.e., generation with no contractual obligation to serve load) – almost 25 GW was uncommitted in the SERC region in 2010.
    - Because uncommitted generating capacity is not included in NERC's reserve margin assessments, there will be additional capacity available above that which is reflected in NERC's projected reserve margins.

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[2] Florida Public Service Commission, Final Order Approving Projected Expenditures And True-Up Amounts For Environmental Cost Recovery Factors For Florida Power & Light Company, Docket No. 100007-E, January 31, 2011 (available at: http://www.floridapsc.com/library/filings/11%5C00735-11%5C00735-11.pdf).

[3] The report provides an assessment assuring SERC's Board of Directors that the planning undertaken by registered entities in the SERC region is carried out in accordance with NERC reliability standards and applicable SERC supplements and criteria. The report also provides an opportunity for SERC members to express to the SERC Board their concerns on current and future matters or issues, which may affect the reliability of the bulk power system in the SERC region.

- Investment in the transmission system in the U.S. Southeast continues to outpace most regions of the country. Nearly 5,000 miles of new transmission lines are projected to come online between 2010 and 2019.
    - This increase will improve inter-regional transfer capabilities, relieve congestion, and ensure generation deliverability to mitigate localized reliability issues, if any.

The Honorable Charles A. Gonzales

1. **Should there be a neutral third party designated to review the science and cost estimates put forth by both EPA and industry stakeholders with regard to proposed rulemakings? If so, who should that third party be and why?**
   The current regulatory process provides sufficient opportunity for review of the science and cost estimates by EPA and other stakeholders. Through the public comment process, review by the Office of Management and Budget, and Congressional hearings, differing views on the science and cost estimates come to light, and EPA is required to propose regulations consistent with the legislative mandates from Congress. In evaluating whether an additional third party should review such estimates, it is important to consider whether such a process would further delay the regulatory process and hinder the ability to provide industry the regulatory certainty needed for long term business planning and investments.

Thank you for the opportunity to provide answers to these additional questions, and I would welcome any additional questions that you or any other member of the Subcommittee on Energy and Power may have.

Sincerely,

Michael Bradley

Michael Bradley

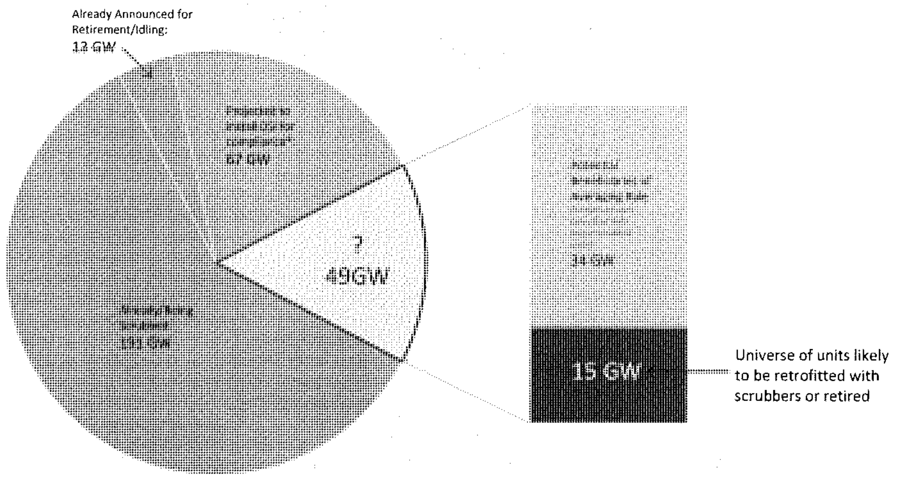
cc: Representative Bobby L. Rush, Ranking Member, Subcommittee on Energy and Power

Appendix to Michael Bradley's Response to Additional Questions for the Record

June 3, 2011

Q: Hearing testimony suggested that 80 to 100 GWs of existing coal-fired capacity would be required to install scrubbers to comply with EPA's proposed emission limits. Do you agree that a significant number of coal-fired power plants will need to install scrubbers?

A: Very few, if any, coal units will be retrofitted with scrubbers as a direct result of EPA's proposed rules.



Sources: EPA, MJB&A Analysis
*estimate by Bernstein Research

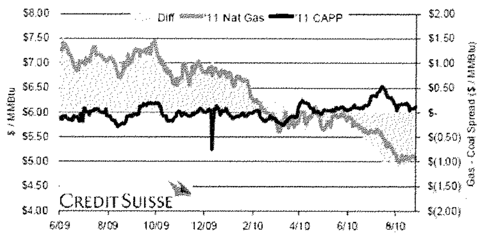
Q: During the hearing, statements were made that 25 to 80 GW of coal-fired capacity would be retired. Please provide your perspective on these estimates. What are the primary drivers of these retirement estimates?

A: The electric industry and investor community expect modest incremental coal capacity retirements. The median projection is 32 GW of retirements nationwide.

Study by	Release Date	Projected Capacity Retirement *(denotes coal capacity only)*	Incremental Retirements *(excludes 13 GW of already announced retirements/idlings)*	Report Title
CERA	March 2011	35 GW (by 2020)	**22 GW**	*Staying Power* *Can US Coal Plants Dodge Retirement for Another Decade? (Private Report)*
Bernstein Research	March 2011	54 GW (by 2014/15)	**41 GW**	*U.S. Utilities: The EPA's Mercury and Air Toxics Standards Are Tougher Than They Appear*
FBR Capital	December 2010	45 GW (by 2018)	**32 GW**	*Coal Retirements in Perspective: Quantifying the Upcoming EPA Rules*
The Brattle Group	December 2010	40-55 GW (by 2020)	**34 GW**	*Potential Coal Plant Retirements Under Emerging Environmental Regulations*
NERC	October 2010	15-35 GW (by 2018)	**12 GW**	*2010 Special Realibility Scenario Assessment: Resource Adequacy Impacts of Potential U.S. Environmental Regulations*
Credit Suisse	September 2010	60 GW (by 2017)	**47 GW**	*Growth from Subtraction: Impact of EPA Rules on Power Markets*
PIRA Energy Group	April 2010	30-40 GW (by 2015)	**22 GW**	*EPA's Upcoming MACT: Strict Non-Hg Regs* *Can Have Far-Reaching Market Impacts*

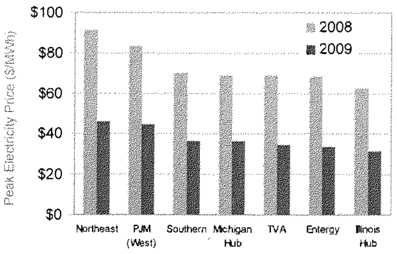
Coal plant retirements will ultimately be driven by their profitability, which depends on wholesale electricity prices and forward coal-gas price differentials. Low electricity and natural gas prices are casting significant doubt on the profitability of many existing coal plants. Their deteriorating economics are putting these plants at risk of retirement even before the impact of EPA's proposed regulations are considered.

Central Appalachian Coal (CAPP) futures are at a premium over natural gas on an electricity equivalent basis



Sources: Credit Suisse, Growth From Subtraction: Impact of EPA Rules on Power Markets, 2010

Electricity prices across the country have fallen, on average, 50 percent between 2008 and 2009



Sources: FERC Market Data, MJB&A Analysis

Q: What are the regional capacity margins for each of the regions in the United States, and are there any specific regions of concern for reliability? If so, what frameworks and regulatory tools currently exist to address such concerns?

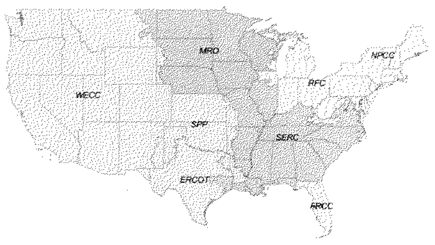
A: The U.S. bulk electric system is divided into eight reliability regions. Analysis by the North American Electric Reliability Corporation indicates that all NERC regions are estimated to have reserve margins in 2014 that are well in excess of the minimum reserve requirements. On an aggregate basis across all NERC regions, the electric sector is expected to have about 145 GW of surplus generating capacity in 2014.

Estimated 2014 Summer Demand, Resources, and Reserve Margins

	Net Internal Demand (GW)	Capacity Resources* (GW)	NERC Reference Reserve Margin Level	Estimated Reserve Margin	Capacity in Excess of NERC Reference Level (GW)
FRCC	44	59	15%	32%	7
MRO	42	53	15%	28%	6
NPCC	63	82	15%	30%	9
RFC	183	245	15%	34%	35
SERC	212	274	15%	29%	30
SPP	46	65	13.6%	40%	12
TRE (ERCOT)	68	89	12.5%	31%	13
WECC	130	183	14.7%	40%	33
Total	788	1,050	15%	33%	145

*Adjusted potential capacity resources

U.S. NERC Electric Reliability Regions



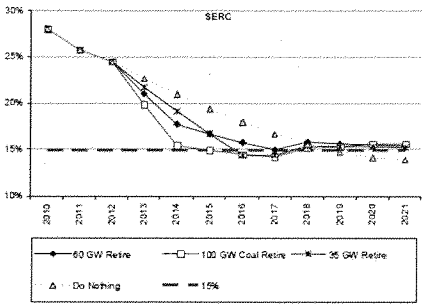
The RFC and SERC regions, where a number of the projected coal retirements are located, are expected to have reserve margins of 34 percent and 29 percent, respectively. These regions, therefore, could retire 35 GW (RFC) and 30 GW (SERC) of existing coal capacity and still maintain the 15 percent NERC reserve margin targets.

The SERC region has adequate excess capacity to absorb regional retirement levels expected by industry analysts.

	2014	2019
Net Internal Demand	212 GW	228 GW
Capacity Resources*	274 GW	284 GW
NERC Reference Reserve Margin Level	15%	
Estimated Reserve Margin	29.4%	24.7%
Capacity in excess of NERC Reference Level	**30 GW**	**22 GW**

*Adjusted potential capacity resources

Even with 60 GW of coal retirements nationwide, SERC reserve margins would not fall below NERC reference levels



Sources: Credit Suisse, Growth From Subtraction: Impact of EPA Rules on Power Markets, 2010

Although adequate reserve margins exist at the aggregate level, power plant retirements may nevertheless trigger localized reliability concerns in some cases. Assorted risk management procedures under the Clean Air Act (CAA), Federal Power Act (FPA), and other statutes provide the EPA, DOE, FERC, and the U.S. President an array of tools to moderate, when and where necessary, potential impacts on electric system reliability.

Agency	Source of Authority / Instrument of Implementation	Measure – Examples
Federal Energy Regulatory Commission – Regional Wholesale Electricity Markets (e.g: PJM, ISO-NE, etc.)	Enforcement of Market Rules, Reliability-Must-Run (RMR) agreements, Forward Capacity Markets, etc.	RMR agreements allow units to operate only to ensure reliability while minimizing adverse environmental impacts Forward capacity markets provide a mechanism to signal the need for new capacity additions
State Public Utility Commissions	Regulatory oversight of utilities	Adopt ratemaking policies that encourage system reliability and environmental goals including ones that address utilities' financial disincentives where EE and DR programs lower utility revenues
U.S. Department of Energy	Section 202(c) of the Federal Power Act	Override CAA-derived control requirements in limited emergency circumstances
U.S. Environmental Protection Agency	Section 112(i)(3)(B) of the CAA	Extend deadlines in Toxics Rule, on a case-by-case basis, for up to one year to allow for installation of control technologies
U.S. President	Section 112(i)(4) of the CAA	Extend deadlines for the Toxics Rule if technologies are not available and it is in the national security interests of the U.S. to do so

Q: Do EPA's proposed emission limits in the utility air toxics rule reflect the performance of any existing plants? If so, please provide a list of the plants that already achieve all of EPA's proposed utility air toxics emission limits.

A: Based on emission rates reported by companies to EPA, many existing U.S. coal-fired units are already compliant with all of EPA's proposed limits for coal-fired electric generating units.

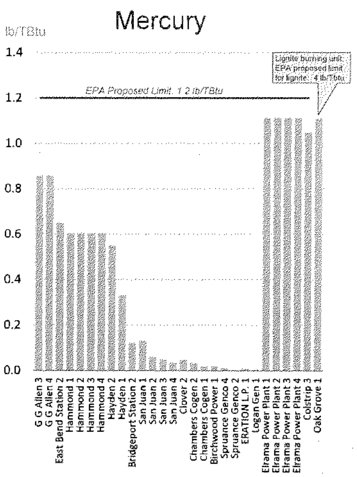
Plant Name	State	Unit	Owner	MW	Coal Rank	PM Control	NOx	SO_2	Hg	Compliance Status Mercury	HCl	PM
G G Allen	NC	3	Duke	282	bituminous	ESP	SNCR	Wet		✓	✓	✓
G G Allen	NC	4	Duke	297	bituminous	ESP	SNCR	Wet		✓	✓	✓
East Bend Station	KY	2	Duke (69%), DPL (31%)	651	bituminous	ESP	SCR	Wet		✓	✓	✓
Hammond	GA	1	Southern	115	bituminous	ESP		Wet		✓	✓	✓
Hammond	GA	2	Southern	115	bituminous	ESP		Wet		✓	✓	✓
Hammond	GA	3	Southern	115	bituminous	ESP		Wet		✓	✓	✓
Hammond	GA	4	Southern	520	bituminous	ESP	SCR	Wet		✓	✓	✓
Hayden	CO	2	Xcel (53%), SRP (30%), MidAmerican (17%)	285	bituminous	FF		Dry		✓	✓	✓
Hayden	CO	1	Xcel (53%), SRP (30%), MidAmerican (17%)	202	bituminous	FF		Dry		✓	✓	✓
Bridgeport Station	CT	2	PSEG	403	subbituminous	ESP + FF			ACI	✓	✓	✓
San Juan	NM	1	PNM Resources (47%), UniSource (20%)	370	subbituminous	FF		Wet	ACI	✓	✓	✓
San Juan	NM	2	PNM Resources (47%), UniSource (20%)	370	subbituminous	FF		Wet	ACI	✓	✓	✓
San Juan	NM	3	PNM Resources (47%), UniSource (20%)	544	subbituminous	FF		Wet	ACI	✓	✓	✓
San Juan	NM	4	PNM Resources (47%), UniSource (20%)	544	subbituminous	FF		Wet	ACI	✓	✓	✓
Clover	VA	2	Dominion	434	bituminous	FF	SNCR	Wet		✓	✓	✓
Chambers Cogeneration LP	NJ	2	Atlantic Power Corporation	285	bituminous	FF	SCR	Dry		✓	✓	✓
Chambers Cogeneration LP	NJ	1	Atlantic Power Corporation	285	bituminous	FF	SCR	Dry		✓	✓	✓
Birchwood Power Facility	VA	1	J-Power	222	bituminous	FF	SCR	Dry		✓	✓	✓
Spruance Genco, LLC	VA	4	Cogentrix	57	bituminous	FF		Dry		✓	✓	✓
Spruance Genco, LLC	VA	2	Cogentrix	57	bituminous	FF		Dry		✓	✓	✓
INDIANTOWN COGENERATION L.P.	FL	1	Indiantown Cogeneration LP	361	bituminous	FF	SCR	Dry		✓	✓	✓
Logan Generating Plant	NJ	1	Keystone Urban Renewal LP	242	bituminous	FF	SCR	Dry		✓	✓	✓
Oak Grove	TX	1	Energy Future Holdings	817	lignite	ESP + FF	SCR	Wet	ACI	✓	✓	✓
Elrama Power Plant	PA	1	GenOn	100	bituminous	ESP + FF	SNCR	Wet		✓	✓	✓
Elrama Power Plant	PA	2	GenOn	100	bituminous	ESP + FF	SNCR	Wet		✓	✓	✓
Elrama Power Plant	PA	3	GenOn	125	bituminous	ESP + FF	SNCR	Wet		✓	✓	✓
Elrama Power Plant	PA	4	GenOn	185	bituminous	ESP + FF	SNCR	Wet		✓	✓	✓
Colstrip	MT	3	PPL (30%), Puget (25%), PGE(20%), Avista (15%), MidAmerican (10%)	805	subbituminous	Venturi		Wet	ACI	✓	✓	✓
PSEG Mercer Generating Station*	NJ	2	PSEG	343	bituminous	ESP + FF	SCR	Dry	ACI	✓	✓	✓
PSEG Mercer Generating Station*	NJ	1	PSEG	343	bituminous	ESP + FF	SCR	Dry	ACI	✓	✓	✓
Brandon Shores*	MD	1	Constellation	643	bituminous	ESP + FF	SCR	Wet	ACI	✓	✓	✓
Brandon Shores*	MD	2	Constellation	643	bituminous	ESP + FF	SCR	Wet	ACI	✓	✓	✓
PSEG Hudson Generating Station*	NJ	2	PSEG	608	bituminous	FF	SCR	Dry	ACI	✓	✓	✓
				11,468								

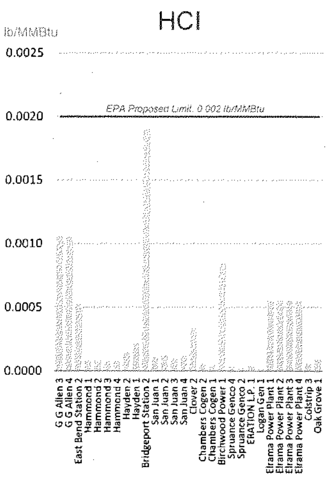
Sources: EPA, Plant Owners, MJB&A Analysis

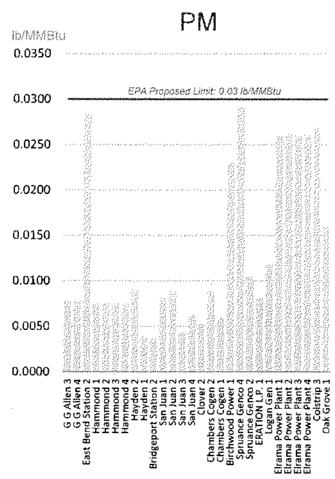
*These units are not present in the ICR database. Information from their owners, however, indicate that they would be able to comply with the proposed standards without the need for any additional controls.

Most of the compliant coal-fired units' reported emission rates are significantly lower than EPA's proposed limits

(based on emission rates reported by companies to EPA)



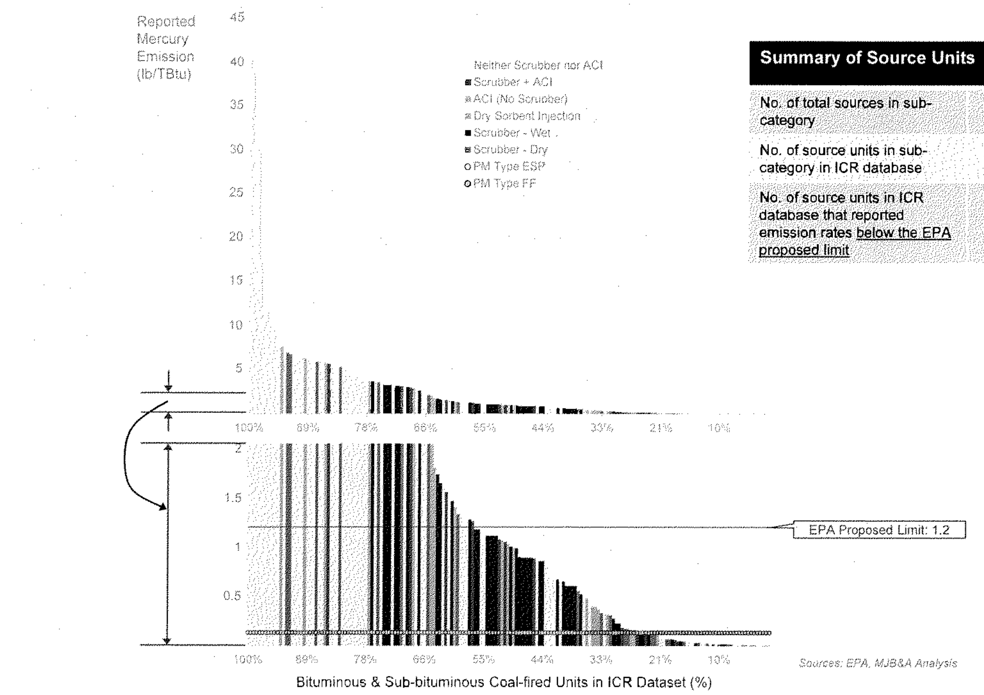




Sources: EPA, MJB&A Analysis

Among coal-fired units that submitted emission data under EPA's most recent ICR*, nearly 60% of units are compliant with EPA's proposed limit for mercury

Information Collection Request

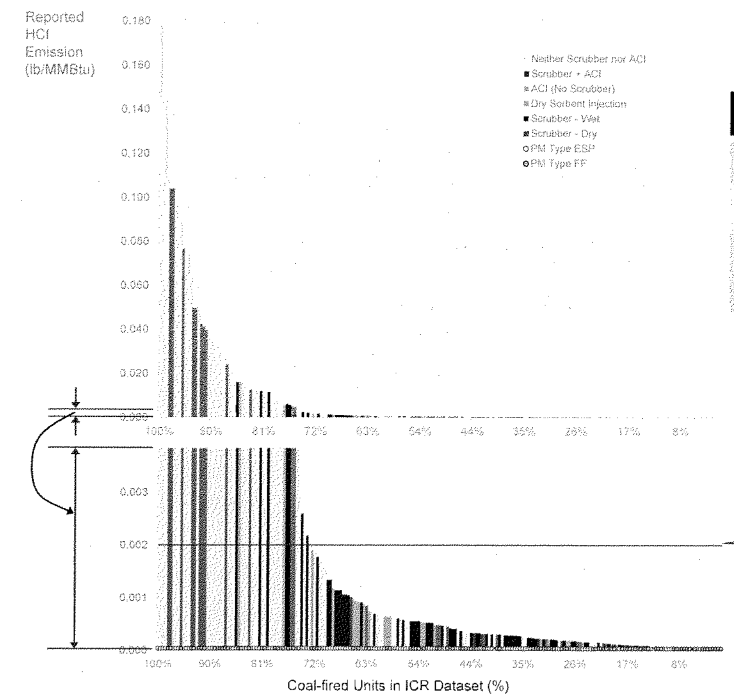


Summary of Source Units	
No. of total sources in sub-category	1,061
No. of source units in sub-category in ICR database	178
No. of source units in ICR database that reported emission rates below the EPA proposed limit	101

Sources: EPA, MJB&A Analysis

Among coal-fired units that submitted emission data under EPA's most recent ICR*, 73% of units are compliant with EPA's proposed limit for HCl

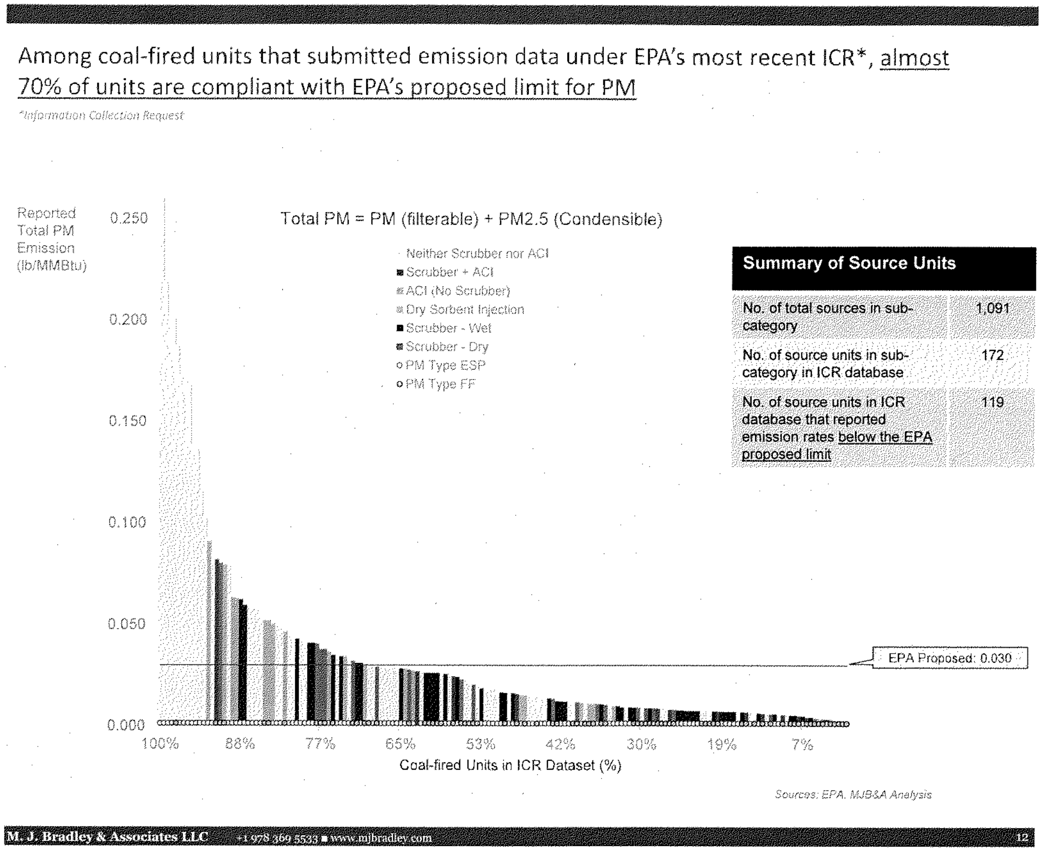
*Information Collection Request



EPA Proposed: 0.0020

Summary of Source Units	
No. of total sources in sub-category	1,091
No. of source units in sub-category in ICR database	217
No. of source units in ICR database that reported emission rates below the EPA proposed limit	158

Sources: EPA, MJB&A Analysis



Among coal-fired units that submitted emission data under EPA's most recent ICR*, almost 70% of units are compliant with EPA's proposed limit for PM

*Information Collection Request

Total PM = PM (filterable) + PM2.5 (Condensible)

Summary of Source Units	
No. of total sources in sub-category	1,091
No. of source units in sub-category in ICR database	172
No. of source units in ICR database that reported emission rates below the EPA proposed limit	119

Sources: EPA, MJB&A Analysis

Dry Sorbent Injection (DSI)

- Dry Sorbent Injection (DSI) reduces SO_2 and other acid gases through the injection of a chemical reagent and with a downstream PM control device to capture the reaction products.

- Reagents used in DSI systems include sodium bicarbonate, hydrated lime, and a natural occurring mixture of sodium carbonate and sodium bicarbonate called *Trona*.

- Relative to a scrubber, DSI is a low capital cost alternative for controlling SO_2 and acid gas emissions, and can generally be installed within 12 months. DSI costs have been estimated at $65/kW.[2] Midwest Generation estimates that it can retrofit its entire coal fleet with DSI and fabric filters within 12 to 24 months (of decision) at a cost of $232/kW.[3] By contrast, a scrubber alone can cost over $400/kW.[4] Generally, DSI will be considered for coal units burning low sulfur PRB coal. Other factors that will drive the deployment of DSI include unit size, percentage reduction of emissions required, plant economics, and site specific characteristics.

- DSI has been deployed in a range of applications for acid gas control, including the electric generating sector. Additionally, companies have announced plans to install DSI technology after detailed research and testing.
  - In 2010, NRG's Dunkirk and Huntley power plants installed DSI systems that simultaneously inject Trona and powder-activated carbon (PAC). Performance tests indicate that emissions of SO_2 have been reduced by over 55 percent, mercury levels have been reduced by over 90 percent, and particulate levels have been reduced to less than 0.010 lbs/MMBtu. The company considers these installations sufficient and expects no additional environmental capex requirements to comply with the Toxics and Transport rule.[5]
  - Duke Energy installed DSI systems in 2010 at its Gallagher generating station. According to the company, the estimated total cost of the DSI system, to be installed at Units 2 and 4, is $11.6 million or about $41/kW. The system will reduce SO_2 emissions by 50 percent and achieve an emission rate no greater than 0.800 lb/MMBtu. Duke Energy expects the DSI system to help the company comply with the requirements of the Toxics and Transport Rule.[6]
  - GenOn operates a DSI system at its Potomac River Generating Station in Alexandria, Virginia. According to the company, the Potomac River plant has seen up to 80 percent reduction in SO_2 emissions since introducing the trona-based system.
  - Midwest Generation is another company that is seeking to retrofit its coal fleet (12 coal-fired units in the Midwest with total capacity of about 5 GW) with DSI technology and upgrading their particulate systems at a total estimated cost of $1.2 billion.[7] In November 2010 and February 2011, Midwest Generation obtained construction permits from the Illinois EPA to install DSI systems at its Waukegan and Powerton generating stations.[8]
  - Conectiv Energy installed a Trona based DSI system at its Edge Moor plant (Units 3 and 4) and operated it from 2009 to mid-2010 on bituminous coal. The plant has since been converted to run on natural gas obviating the need for the DSI system.[4]
  - Portland General Electric is in the process of installing a DSI system at its Boardman plant in Oregon. The company expects the system to be online in July 2014 to comply with Oregon Department of Environmental Quality's BART standards.

- The basic reagent injection technology underlying DSI systems is mature and has been in service for more than 20 years at dozens of other coal-fired power plants.[9,10]

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[1] Institute of Clean Air Companies. *Letter to Senator Thomas Carper. U.S. Senate.* November 2010
[2] U.S. EPA. *Documentation Supplement for EPA Base Case v4.10_PTox- Updates for Proposed Toxics Rule.* March 2011
[3] Bernstein Research. *U.S. Utilities: The EPA's Mercury and Air Toxics Standards Are Tougher Than They Appear*, March 2011
[4] James E. Staudt. *Control Technologies to Reduce Conventional and Hazardous Air Pollutants from Coal-fired Power Plants*, March, 2011
[5] NRG Energy. *Q1 2011 Earnings Conference Call.* May 5, 2011
[6] Indiana Utility Regulatory Commission. *Petition of Duke Energy Indiana, Inc., for Issuance of a Certificate of Public Convenience and Necessity for use of Clean Coal Technology for a project, Dry Sorbent Injection, at Petitioner's Gallagher Generating Station.* Sep 8, 2010.
[7] Edison International. *Q2 2010 Earnings Call Transcript* (http://www.morningstar.com/earnings/16355020-edison-international-eix-q2-2010.aspx). Accessed May 4, 2011.
[8] Midwest Generation LLC. *Form 10-K.* Feb. 2011.
[9] Babcock and Wilcox. *Dry Sorbent Injection Systems for Acid Gas Control*
[10] EPA NEEDS v 4.10

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The Honorable Charles A. Gonzalez
1436 Longworth House Office Bldg
Washington, DC 20515

RE: Question for the Record of the April 15, 2011 Hearing on EPA rules entitled "The American Energy Initiative" of the House Subcommittee on Energy and Power, Committee on Energy and Commerce

Dear Congressman Gonzalez:

Thank you for your letter regarding the recent Subcommittee hearing on EPA Clean Air Act rulemakings. You asked whether there should "**be a neutral third party designated to review the science and cost estimates put forth by both EPA and industry stakeholders with regard to proposed rulemakings? If so, who should that third party be and why?**" You posed the question in the context of my testimony before the Subcommittee, in which I raised several problems with the EPA Boiler rule.

By way of background, the Boiler rule is one of four complex, interrelated rules proposed on June 4, 2010, by the U.S. Environmental Protection Agency (EPA) under the Clean Air Act (CAA) and the Resource Conservation and Recovery Act (RCRA).[1] These rules cover major industrial, commercial and institutional boilers and process heaters, area-source industrial, commercial and institutional boilers; commercial and industrial solid waste incinerators; and the definition of "solid waste" to demarcate applicability under CAA § 112 and § 129 between boilers and incinerator units. My reference here to "Boiler rule" implicitly includes concerns, where applicable, with the other three interrelated rules.

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[1] National Emission Standards for Hazardous Air Pollutants for Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters, 75 Fed. Reg. 32006 (proposed June 4, 2010) (to be codified at 40 C.F.R. pt. 63)(Boiler Rule); National Emission Standards for Hazardous Air Pollutants for Area Sources: Industrial, Commercial, and Institutional Boilers, 75 Fed. Reg. 31896 (proposed June 4, 2010) (to be codified at 40 C.F.R. pt. 63)(Area Source Rule); Standards of Performance for New Stationary Sources and Emission Guidelines for Existing Sources: Commercial and Industrial Solid Waste Incineration Units, 75 Fed. Reg. 31938 (proposed June 4, 2010) (to be codified at 40 C.F.R. pt. 60)(CISWI Rule); Identification of Non-Hazardous Secondary Materials That Are Solid Waste, 75 Fed. Reg. 31844 (proposed June 4, 2010) (to be codified at 40 C.F.R. pt. 241)(Solid Waste Definition Rule).

In my estimation, requiring another entity to review science and cost data as you suggest would not improve the circumstances of the Boiler rule. In my view, what is key to many of the problems with the Boiler rule is that EPA committed to a timeframe for developing the Boiler rules that was inadequate to the undertaking. Throughout the process of developing the rule, EPA was compelled by deadlines to cut short every step of the rulemaking process. The impact of the deadlines on the Boiler rulemaking is more fully described in the attached letter of the Council of Industrial Boiler Owners and other industry representatives to EPA Administrator Jackson, seeking additional time for public comment.

From the outset, it was clear that these interrelated rules were unprecedented in terms of complexity, breadth of applicability and cost on the regulated community. As proposed, EPA estimated the capital cost only (not including millions in increased annual operations costs) for regulated sources to comply with the Boiler rule only (not including costs to comply with the other three related rules) to be $10 billion. Those of us who face firsthand the challenges of planning and overseeing large equipment modifications at complicated industrial or institutional facilities, estimated that the cost to comply was more realistically twice that amount, about $20 billion. Yet even by EPA's estimate, the sizeable impact of these rules on regulated sources merited the utmost care in data collection and analysis, and in particular extended public notice and comment. However, EPA's deadlines forced it to take shortcuts that I do not believe Congress had in mind in establishing rulemaking proceedings for EPA and other administrative agencies.

The most fundamental problem – inadequate time for four rules of this complexity – would not be cured by adding layers of data review, but only by granting EPA adequate time to thoughtfully re-examine the rules and address their deficiencies.

Thank you for the opportunity to respond to your question for the record.

Very truly yours,

/s/ Paul A. Kempf

Paul A. Kempf, P.E.
Director of Utilities
CIBO University Affiliate Member

cc: Chairman Whitfield, Subcommittee on Energy and Power
Ranking Member Rush, Subcommittee on Energy and Power

Attachment

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June 23, 2010

The Honorable Lisa Jackson, Administrator
U.S. Environmental Protection Agency
Ariel Rios Building
1200 Pennsylvania Avenue, NW
Mail Code: 1101A
Washington, DC 20460

RE: Request to Extend Time to Submit Comments on Proposed Rules

Dear Administrator Jackson:

Enclosed is a request for an extension of time to submit comments on four interrelated proposed rules, submitted on behalf of entities representing diverse sectors of the economy. The 27 undersigned entities seek additional time to comment on EPA's proposed rules setting Clean Air Act hazardous air pollutant emission standards for boilers, process heaters and incinerators, and defining "solid waste." If you have any questions, you may contact me at 202.828.5844.

Very truly yours,

Bracewell & Giuliani LLP

Lisa M. Jaeger

Enclosure

cc: Gina McCarthy, EPA Assistant Administrator for Office of Air & Radiation
Mathy Stanislaus, EPA Assistant Administrator for Office of Solid Waste & Emergency Response
Scott Fulton, EPA General Counsel

June 23, 2010

The Honorable Lisa P. Jackson, Administrator
U.S. Environmental Protection Agency
Ariel Rios Building
1200 Pennsylvania Avenue, N.W.
Mail Code: 1101A
Washington, DC 20460

RE: Request to Extend Time to Submit Comments on Proposed Rules

Dear Administrator Jackson:

This request for an extension of the deadline for comments is submitted by these 27 entities: American Chemistry Council (ACC); American Coke and Coal Chemicals Institute (ACCCI); American Forest & Paper Association (AF&PA); American Iron and Steel Institute (AISI); American Municipal Power, Inc. (AMP) and its generating members that include the City of Painesville, Ohio, the City of Orrville, Ohio, the City of Dover, Ohio, the City of Shelby, Ohio and the City of Hamilton, Ohio; American Petroleum Institute (API); American Public Power Association (APPA); American Sugar Alliance (ASA); Bioenergy Deployment Consortium (BDC); Brick Industry Association (BIA); Composite Panel Association (CPA); Corn Refiners Association (CRA); Council of Industrial Boiler Owners (CIBO); Florida Sugar Industry (FSI); National Association of Manufacturers (NAM); National Oilseed Processors Association (NOPA); National Petrochemical and Refiners Association (NPRA); Pellet Fuels Institute (PFI); Rubber Manufacturers Association (RMA); Society of Chemical Manufacturers and Affiliates (SOCMA); Treated Wood Council (TWC); and Utility Air Regulatory Group (UARG).

On June 4, 2010, the U.S. Environmental Protection Agency (EPA) published four interrelated proposed rules under the Clean Air Act (CAA) and the Resource Conservation and Recovery Act (RCRA): a rule setting major-source National Emission Standards for Hazardous Air Pollutants (NESHAPs) for industrial, commercial and institutional boilers and process heaters under CAA § 112 (Boiler rule);[1] a rule setting area-source NESHAPs for industrial, commercial and institutional boilers under CAA § 112 (Area Source rule);[2] a rule setting New Source Performance Standards (NSPS) and emission guidelines for commercial and industrial solid waste incinerators under CAA § 129 (CISWI rule);[3] and a RCRA rule defining "solid waste" to demarcate applicability under CAA § 112 and § 129 between boilers and CISWI units (Solid Waste Definition rule).[4]

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[1] National Emission Standards for Hazardous Air Pollutants for Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters, 75 Fed. Reg. 32006 (proposed June 4, 2010) (to be codified at 40 C.F.R. pt. 63)(Boiler Rule).

[2] National Emission Standards for Hazardous Air Pollutants for Area Sources: Industrial, Commercial, and Institutional Boilers, 75 Fed. Reg. 31896 (proposed June 4, 2010) (to be codified at 40 C.F.R. pt. 63)(Area Source Rule).

As EPA is well aware, these rules raise an unprecedented number of issues for the Agency in determining the appropriate Maximum Achievable Control Technology (MACT) floors for these very large, diverse source categories. Nevertheless, EPA has provided only 60 days for regulated sources and the public to analyze and comment on these four complicated proposed rules.[5] We appreciate the diligence of EPA staff in providing data and assistance whenever possible. However, such assistance cannot overcome the inadequacy of the comment period, given the challenges of a very large diverse source category and an inadequate period of time for EPA to collect data and conduct quality assurance of that data.

In light of the broad scope and economic impact of the proposed rules, and of EPA's statutory obligation to provide a reasonable opportunity for public comment, we respectfully request that EPA extend the comment period by an additional 90 days, giving the public a total of 150 days during which to comment. We further request that this request and EPA's response be included in the rulemaking docket for each of the four rules at issue.

I. Sixty Days to Comment on the Four Proposed Rules Is Unreasonably Short

A. Sixty Days Does Not Meet the Statutorily Prescribed Minimum Standard

Under basic principles of due process and administrative law, EPA has an obligation to provide the public with a reasonable opportunity to comment on proposed rules. Specifically, Congress required EPA to give the public "a reasonable period . . . of at least 30 days" in which to comment on "any regulation" promulgated under the CAA.[6] By the clear terms of the CAA, Congress indicated that 30 days is the minimum time necessary to give the public a reasonable opportunity to evaluate a proposed rule and provide adequate feedback to the Agency. Thus, a comment period meeting the statutory 30-day minimum would be reasonable for a single, ordinary proposed rule.

Here, EPA has allowed 60 days for four rules. Sixty days – only 30 days longer than the statutory minimum for a single rule – is an unreasonably short period of time for comment on EPA's four interrelated proposed rules. Had EPA issued each of these rules separately, the CAA would have ensured 120 days of comment. EPA's longstanding practice for MACT rules would have indicated at least 60 days to comment on each rule, for a total of 240 days. As more fully discussed below, one of the proposed rules – the Solid Waste Definition Rule – presents threshold applicability questions that a large percentage of sources must consider. Once they determine the potential applicability of the Solid Waste Definition rule, then they must evaluate what aspects of the remaining *three* proposed rules pertain to them; analyze the rules' effects; and provide meaningful comments. For EPA to provide only 60 days of comment violates the clear terms of the CAA and deprives sources of a means to adequately protect their interests and rights in the administrative and judicial processes.

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[3] Standards of Performance for New Stationary Sources and Emission Guidelines for Existing Sources: Commercial and Industrial Solid Waste Incineration Units, 75 Fed. Reg. 31938 (proposed June 4, 2010) (to be codified at 40 C.F.R. pt. 60)(CISWI Rule).

[4] Identification of Non-Hazardous Secondary Materials That Are Solid Waste, 75 Fed. Reg. 31844 (proposed June 4, 2010) (to be codified at 40 C.F.R. pt. 241)(Solid Waste Definition Rule).

[5] *See* 75 Fed. Reg. 32682 (June 9, 2010)(extending initial 45-day comment period to 60 days).

[6] 42 U.S.C. § 7607(h) (2006).

Although EPA released the signed rule proposals approximately one month[7] prior to their publication in the Federal Register, during the period from their release on that date until their publication in the Federal Register on June 4, 2010, EPA did not provide access via the docket to the majority of documents underlying the proposed rules. In particular, EPA did not release the most critical document that could have permitted an early start on analyzing EPA's proposal – the MACT floor analysis.[8] In some cases, after considerable effort by regulated sources, EPA made some data available; however, this was on an as-requested, case-by-case basis. Therefore, regulated sources were hampered and continue to be hampered[9] in their efforts to use that time to analyze EPA's data, analysis, and rationale for its proposed rules.

B. Sixty Days is Unreasonably Short Given the Complexity, Breadth of Applicability, and Economic Impact of the Proposed Rules

A 60-day period is particularly inadequate given the complexity, breadth of applicability, and economic impact of the proposed rules. Each of the proposed rules, considered alone, is complex. Moreover, because EPA published the four rules simultaneously, regulated facilities must also assess the impact of the rules as they interrelate, raising many more operational and practical questions. Once operational issues are assessed, regulated entities must develop comments to preserve all possible factual and legal issues raised by the rules.

Given that the previous Boiler MACT rule was vacated because EPA did not adequately address the nature of the relationship between these rules, EPA arguably should have proposed the rules sequentially, beginning with the Solid Waste Definition rule. The Solid Waste Definition rule establishes the regulatory characterization of materials combusted as either waste or fuel, thereby also establishing the categorization of a source combusting those materials as either an incinerator or a boiler. Establishing this categorization is necessary to avoid a repeat vacatur of a final Boiler MACT rule, should the Solid Waste Definition rule be challenged and changed in such a way that the source categories and floor calculations are affected.

The simultaneous proposal of the rules greatly complicates the analysis of whether the standards can be achieved by affected sources. A large percentage of sources must first apply a complex set of factors under the Solid Waste Definition rule to each material they combust, to determine whether EPA is likely to consider the material a waste or a fuel. If the materials would be considered *solid waste*, the source combusting those materials would be considered an

---

[7] EPA posted a version of the rules on its website April 30, 2010.

[8] The MACT floor memorandum – "MACT Floor Analysis (2010) for the Industrial, Commercial, and Institutional Boilers & Process Heaters NESHAPS – Major Source."—was referenced on p. 87 of the proposal posted on the web, but was not released until the rule proposal was published in the Federal Register. The memo may now be found at EPA-HQ-OAR-2002-0058-0815.

[9] For example, as discussed below, EPA did not release spread sheets indicating how the Agency established floors for Boilers until June 21, 2010 and as of June 23, 2010, had not released spread sheets for floor setting for CISWI units.

incinerator, and it must then consider the applicability and achievability of the *CISWI* standards. On the other hand, if under the Solid Waste Definition rule, the materials are characterized as *fuel*, the source combusting those materials would be considered a *boiler*, and the source must then consider the applicability and potential achievability of the *Boiler rule* (for a major source) or *Area Source rule* (for a non-major source) standards. Therefore, the interrelationship of the rules requires a step-wise analysis by covered entities. Many entities operate units with potential applicability of either the CISWI or Boiler rule, for more than one material combusted, requiring an in-depth step-wise analysis for each material combusted for each unit. In addition, EPA has proposed an alternative approach to making the initial solid waste/fuel determination. Sources must also consider, for each material combusted, this alternative approach as compared to the first proposed approach to distinguishing between a waste and fuel. Until the Solid Waste Definition rule is finalized, there will be a great deal of uncertainty as to whether a source will be regulated as a boiler or an incinerator.

Given the simultaneous proposal of all four rules, EPA is forcing sources to undertake simultaneous applicability and achievability analyses of multiple rules. Under ordinary circumstances, an entity could accomplish a rule analysis and comment in 60 days. These incomparable circumstances make the 60-day period unconscionably short.

In addition to the rules' complexity, the rules will have an extraordinary impact in terms of applicability and compliance costs. EPA estimates the Boiler MACT rule would cover approximately 13,555 units located at 1,608 different facilities.[10] For its initial data collection under the Information Collection Request Phase 1, EPA's database included facilities representing 50 NAICS codes nationwide. The rule will cover such diverse sources as manufacturing facilities, educational services (colleges and universities), hospitals, nursing and residential care facilities, and national security (military bases). Under the proposed rule, these units would be placed into one of 11 subcategories, each of which would be subject to different emission requirements.[11] EPA estimates that the cost to boilers and process heaters to comply with the Boiler MACT rule would be $9.5 billion in capital expenditures and $3.2 billion in total annual costs.[12]

In addition, EPA estimates the Area Source rule would cover approximately 183,000[13] existing boilers at 91,000 facilities[14] nationwide and the approximately 6,800 new boilers projected to be installed over the next three years.[15] EPA estimates that the total annualized cost to comply with this rule would be $1 billion.[16] EPA estimates that the CISWI rule will affect 176 units[17] at a compliance cost of $574 million in total capital investment and $216 million in total annual costs.[18] Finally, the Solid Waste Definition rule would cover sources at facilities from a wide range of sectors, covering at least 85 different NAICS codes according to EPA.[19]

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[10] 75 Fed. Reg. 32048.

[11] *See* 75 Fed. Reg. at 32012.

[12] *See* 75 Fed. Reg. at 32037. Although these compliance cost estimates are large, the regulated community estimates that the real cost impact on regulated sources of the proposed Boiler MACT rule is far higher, more realistically costing at least $20 billion in capital costs and $4 billion in annual costs. Assessing a true cost impact is among the difficult, time-consuming matters that regulated sources must undertake. An accurate estimate is necessary to evaluate the relative benefit of the proposed rules. More fundamentally, however, this assessment is critical for companies to start planning for such internal decision-making as capital investment, contract planning for equipment installations, and in this case, even contract planning regarding what type of fuel materials to consider for future operations. This activity is further complicated by uncertainty of final rule requirements, which will be based on EPA's evaluation of comments on the proposed rules.

[13] 75 Fed. Reg. at 31914.

[14] 75 Fed. Reg. at 31924.

[15] 75 Fed. Reg. at 31914.

The combination of the four proposed rules makes for an enormously broad and costly proposal, which would have a significant economic impact across numerous and diverse sectors of the US economy. This economic impact alone requires a comment period sufficient to ensure thorough consideration of the proposed rules. The need for an adequate period of time in which to assess the rules is especially acute for the tens of thousands of sources that must asses the potential impact of the rules, and then may be forced to incur crippling compliance costs under the rules. It is simply unjustifiable to give these sources 60 days in which to evaluate the proposed rules in light of the rules' complexity and economic consequences.

C. Sixty Days Is Unreasonably Short When Compared to the Amount of Time EPA Allocated to Itself to Gather Data, Develop the Proposed Rules, and Issue the Final Rules

The insufficiency of the current comment period is especially pronounced when compared to the lengthy period of time EPA allocated to itself to collect and analyze the data underlying the proposed rules. EPA began a two-phase data collection effort after the previous Solid Waste Definition and Boiler MACT rules were vacated on June 8, 2007.[20] In December 2007 and again in May 2008, EPA solicited information from regulated sources to assist in the development of emissions standards for boilers, process heaters, and CISWI units.[21] Thus, for a minimum of 30 months, EPA has been collecting and analyzing data to develop emissions standards regulating boilers, process heaters, and CISWI units. EPA has also reserved for itself almost 4 months to review comments and prepare a final rule. Although 4 months is a woefully short period of time for EPA to thoroughly address the many complex issues raised by these rules, it is twice the amount of time that EPA has seen fit to provide the regulated community to conduct its own analysis of the data and impact of the proposed rules. In contrast to the 34 months that EPA has allocated to its own rulemaking efforts, EPA gave sources affected directly and indirectly by the rules only 2 months to evaluate the same data and proposed standards, and then write substantive comments that could meaningfully inform the rulemaking process.

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[16] *Id.*

[17] 75 Fed. Reg. at 31950-51.

[18] 75 Fed. Reg. at 31967.

[19] 75 Fed. Reg. at 31845.

[20] *See Natural Resources Defense Council v. EPA*, 489 F.3d 1250, 1257-61 (D.C. Cir. 2007).

[21] *See* Agency Information Collection Activities: Information Request for National Emission Standards for Industrial, Commercial, and Institutional Boilers and Process Heaters, 72 Fed. Reg. 69213 (Dec. 7, 2007)(ICR No. 2286.01); Agency Information Collection Activities; Information Collection Effort for Facilities with Combustion Units, 73 Fed. Reg. 27820 (May 14, 2008)(ICR No. 2286.03).

D. Sixty Days is Unreasonably Short Given the Inaccuracies in the Database and File Formats that do not Permit Technical Verification of EPA's Calculations

Providing a meaningful analysis of the data underlying the proposed rules is a time-consuming process. This is particularly so when, as here, the accuracy of EPA's data is at issue.

1. Data Errors Must Be Corrected Before Floor Analysis Can Be Verified

EPA adopted a very aggressive timeframe for developing these rules. EPA's data gathering process, more fully explained in Attachment A, demonstrates why any meaningful comment on the rules must begin with checking data accuracy. The database contains 44,389 records with emission test results; 92,822 records with fuel analysis information; and 44,219 records with continuous emission monitoring systems (CEMS) data. The data reflect inconsistencies between facilities' hard copy test reports submitted to EPA and the same data in EPA's databases. To date, a limited review of some of the data being used to set standards for the Boiler rule reveals errors in units of measure, errors in the fuel and boiler categorizations of covered units, errors in calculation of detection limits, and errors in measurement techniques that render test results invalid. Because EPA has not thoroughly reviewed the specific data used to establish MACT floors (as discussed in Attachment A), the sources that submitted data need sufficient time to do a quality analysis of the data to ensure its accuracy in order to comment on the conclusions EPA has reached in reliance on this data.

Errors have been found in data from sources that EPA has identified as "top performers." Errors in top performer data are intolerable because that data is the foundation for EPA's calculation of MACT floors that will apply to all sources in the same subcategory emitting that pollutant. Specific examples of such data errors include: the dioxin/furan limit for biomass stoker boilers and coal fluidized boilers is based on top performer data that had been reported on a Toxic Equivalency Quantity (TEQ) basis was mistakenly corrected to its TEQ value a second time, resulting in values an order of magnitude too low; the CO limit for biomass stoker boilers is based on top performer data from a suspension burner that is misclassified as a stoker; a top performer in the Gas 2 subcategory actually burns petroleum coke (a solid fuel) and not coke oven gas; and the mercury limit for biomass boilers was based on a top performer that did not follow the required Method 29 procedures, where the source has recently asked EPA to remove data from the database. The unacceptability of some data, as perhaps occurred in this last example, is unavoidable due to the short timeframe adopted for the ICR testing, as described in Attachment A.

2. Analysis Of Floor-Setting Calculations Is Still Not Realistically Possible

Although the comment period began on June 4, 2010, EPA did not make MACT floor memo Excel files available in the docket for the Boiler rule until June 21, and has still not made those files available for the CISWI rule. EPA has indicated that it will add the Excel files for CISWI units to the docket by June 28, 24 days into the 60-day comment period.

The Excel file format is crucial to analyzing EPA's floor analysis with any degree of efficiency. The April 2010 MACT Floor Analysis[22] explains how EPA derived the MACT floor values. It explains that statistical parameters were calculated using Excel functions. However, the floor memos and appendices are in pdf format, which does not allow technical reviewers to verify how EPA calculated floors, statistical calculations and other critical values presented in these memos. By clicking on a particular cell in an Excel file, one can see what formula and dataset were used. EPA itself used Excel files to do the calculations and those files would show the user what formulas EPA used to arrive at their values. The alternative would be for a reviewer to load data manually into an Excel file which is time-consuming, expensive, and duplicative of work already done by EPA.

Since early May, requests have been made for EPA to release the Excel files. EPA released the Boiler MACT Excel files on June 21, 2010, but reportedly will not release the CISWI Excel files until June 28. Sources should have complete access to these important documents. EPA has responded that time is needed to remove deliberative information from the files before release. Regulated sources respect EPA's need to protect deliberative information and recognize that its removal from the files will take time. However, affected sources needing access to data should not bear the brunt of EPA's data formatting delays by not having an adequate comment period. Commenters cannot re-create the Excel spreadsheets from listed pdf values in the short comment period nor should EPA thrust on sources the additional cost to recreate Excel files that already exist. EPA has required that regulated sources utilize specific electronic reporting tools and formats when reporting data to EPA, in order to improve the efficiency and accuracy of EPA's process. It is irrational to impose efficiency measures on the reporting sources and then deny those same sources an efficient means (which need not be separately developed) to recreate EPA's complicated calculations and assess the workability and impacts of proposed emission limits.

Given the complexity of MACT standard-setting, EPA in the past has quickly made these Excel files available, most recently for the MACT for hospital, medical, and infectious waste incinerator (HMIWI MACT) and for the Municipal Waste Combustor MACT. The same should be done here, where EPA has given sources in much broader categories a much shorter time to verify data and analyze EPA's standards.

E. Sixty Days Is Unreasonably Short When Compared to the Amount of Time EPA Has Allocated to Other Less Complex and Less Costly Proposed Rules

EPA has provided more time to comment on proposed MACT rules that were much narrower in scope of applicability, less complex, and of less costly impact to the broader economy than the current proposals. For example, EPA provided a 60-day comment period for the rule establishing HMIWI MACT standards.[23] The HMIWI MACT covered 57 then-existing units which were divided into two broad categories under the rule.[24] EPA estimated that the total compliance cost would be approximately $15.5 million in each of the first three years of compliance.[25]

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[22] Memorandum from Amanda Singleton, ERG, EPA-HQ-OAR-2002-0058-0815.

[23] 75 Fed. Reg. 27249 (May 14, 2010).

[24] 40 C.F.R. 60.30(e), 74 Fed. Reg. 51397 (Oct. 6, 2009).

For MACT rulemakings focused on less diverse source categories, like Portland Cement plants (Portland Cement MACT), EPA provided a 60-day comment period,[26] which the Agency extended an additional 60 days, for a total 120-day comment period.[27] While the Portland Cement MACT regulates a comparatively more similar population of plants,[28] the units that would be covered by the current proposals vary considerably in size, type, and structure. Compliance with the current proposals may require different solutions for each unit depending upon their distinguishing factors, as well as consideration of the controls each unit already has in place. Thus, a longer comment period is needed for communication and coordination on these current rule proposals.

The proposed rule to establish emission standards for Reciprocating Internal Combustion Engines (RICE MACT) included a 60-day comment period,[29] which EPA extended by an additional 30 days, for a total 90-day comment period.[30] In the final rule, EPA estimated total capital costs of $744 million and total annual costs of $373 million to comply with the RICE MACT.[31] As noted above, EPA estimates the total costs to boilers, process heaters and CISWI units under these proposed rules would exceed $10 billion.[32]

Because of the economic effect that these rules would have on a broad spectrum of regulated entities and their employees, it is in the best interest of the Agency, as well as the affected parties, to provide a longer comment period to ensure meaningful public participation.

II. The Impacts of the Rules on Affected Small Businesses Require an Extension of the Comment Period to Ensure Meaningful Comments from those Entities.

The broad impact of these rules means that many entities affected are small businesses or small entities with limited resources to track and participate in Clean Air Act rulemakings. EPA determined through a screening analysis that the Boiler MACT rule and the Area Source rule would have a significant effect on a substantial number of small business entities.[33] With the Regulatory Flexibility Act (RFA) as amended by the Small Business Regulatory Enforcement Fairness Act (SBREFA), Congress sought to address agency behavior "resulting in greater regulatory burdens on small entities than necessitated by statute …".[34] Extending the time for public comment will help affected small entities by providing more time to digest the proposed rules, to engage the resources to fully understand their potential impact, and to generate the data and information for effective public comment participation. With additional time, small entities can help EPA better understand the potential impact of its proposed rules, including the Boiler rule's significant impact on small governments, which EPA negates in its Unfunded Mandates Act statement.[35]

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[25] *Id.*
[26] 40 C.F.R. § 60, 63, 74 Fed. Reg. 21136 (May 6, 2009).
[27] 74 Fed. Reg. 27265 (June 9, 2009).
[28] *See id.*
[29] 74 Fed. Reg. 9698 (Mar. 5, 2009).
[30] *See* Response to Public Comments on Proposed NESHAP for Existing Stationary RICE Located at Area Sources of HAP Emissions at 32, EPA-HQ-OAR-2008-0708 (Feb. 23, 2010).
[31] 40 C.F.R. 63, 75 Fed. Reg. 9669 (Mar. 3, 2010).
[32] *See id.* at 159.
[33] *See* 75 Fed. Reg. 32044 (June 4, 2010).
[34] SBREFA Section 202(4).

III. An Additional 90 Days Will Allow Commenters to Include Test Data Generated in Response to Data Gaps in EPA's Database

The Boiler rule would also benefit significantly from the generation of additional emissions information. EPA's MACT Floor tables indicate that eleven of the thirty MACT Floor emission limitations for existing sources were determined using less than five sources due to a lack of available data.[36] This despite a clear preference from Congress that EPA rely on no less than five sources when setting emission standards for existing sources under Section 112(d).[37] Allowing additional time during the public comment period would enable sources to generate some additional emissions information, subject to the availability of testing companies, with proper quality assurance and quality control to assess the reliability of existing data and to establish a more robust basis for setting MACT limits.

IV. EPA Is Authorized to Provide a Longer Comment Period, Is Not Bound By a Judicial Deadline in the Underlying Case Of *NRDC v. EPA*, and Could Re-Negotiate Deadlines to Which EPA Sought to be Bound

EPA is not constrained in its ability to provide an extended comment period because it is not bound by a judicial deadline in *Natural Resources Defense Council v. EPA* to propose or finalize standards for boilers, standards for incinerators, or a definition of solid waste.[38] In *NDRC v. EPA*, the court vacated the Boiler MACT and Solid Waste Definition rules. The court did not impose a deadline on EPA to revise the Boiler MACT standards or definition of solid waste. Therefore, in the lawsuit underlying the MACT standards, EPA retained the ability to allocate a reasonable amount of time to gather data, develop standards and provide an adequate public comment period for re-proposing the vacated rules.

However, EPA agreed to and sought court orders for deadlines for issuing Boiler MACT and Definition rules in the unrelated case of *Sierra Club v. Jackson*.[39] *Sierra Club* involves a challenge to EPA for failing to meet a deadline to issue MACT standards for area sources. Area-sources and major-source boilers/process heaters are in separate and independent CAA source categories.[40] Petitioners in the *Sierra Club* area-source deadline case did not raise the substantive issues before the court in the major-source *NRDC v. EPA* case, including MACT floor setting, compliance alternatives and the definition of "solid waste." Sources directly regulated by the Boiler MACT and Definition rules were not parties to *Sierra Club* and had no opportunity to participate in negotiations between Petitioners and EPA in that case. Entities regulated by the Boiler MACT rule learned of the rulemaking deadlines only after the court entered the deadlines, because the deadline was worked out during confidential negotiations. Further, although some regulated sources directly regulated by Boiler MACT were Respondent-Intervenors in *Sierra Club*, EPA and Petitioners excluded those parties from the negotiations.

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[35] *See* 75 Fed. Reg. 32044.

[36] *See* Table 2 and Table 3, 75 Fed. Reg. 32022-32023 (June 4, 2010).

[37] *See* 42 U.S.C. 7412(d)(3)(B), CAA 112(d)(3)(B).

[38] *See Natural Resources Defense Council v. EPA*, 489 F.3d 1250 (D.C. Cir. 2007).

[39] *See Sierra Club v. Jackson*, No. 01-537 (D.C. Cir.) (Nov. 10, 2008 Order linking the area source deadline extension to deadlines for MACT standards for boilers, process heaters and CISWI units); (April 13, 2010 Order extending the deadline to December 16, 2010 for EPA to finalize MACT standards for boilers, process heaters and CISWI units).

[40] *Compare* 42 U.S.C. § 112(a)(1) (defining major sources), *with* 42 U.S.C. § 112(a)(2) (defining area sources).

Notwithstanding the absence in *Sierra Club* of substantive issues presented, and the absence of directly affected entities as parties, EPA and Petitioners in *Sierra Club* agreed to deadlines for the revision of the Boiler MACT and Definition rules not at issue in that case. Thus, in spite of no judicial deadline imposed by the court in the case vacating the Boiler MACT and Definitions rules, EPA has in separate litigation, sought a court order imposing the rulemaking deadlines now constraining the MACT rulemaking process. In bluntest terms, EPA effectively traded away the rights of the directly affected regulated community to meaningfully participate in a rulemaking process, and now EPA is hiding behind that deadline to impose an unreasonably short comment period for these complicated rules.

Although EPA asserts that the December 2010 deadline is a judicial deadline that cannot be changed, on several occasions, EPA has renegotiated the deadlines and filed unopposed motions to extend the deadlines in *Sierra Club*.[41] Thus, EPA has the ability to approach the court to establish deadlines that reflect the realities of the rulemaking proceeding such that adequate time can be provided for proper comment and EPA deliberation regarding those comments prior to final rule development and promulgation in order to minimize the potential for subsequent litigation.

V. A Longer Comment Period Should Be Coordinated With the Timing of any § 112(j) Case-By-Case MACT Program

The shortness of the comment period is further complicated by the fact that EPA recently proposed another rule for comment, which attempts to activate the § 112(j) process – the MACT "hammer" or "case-by-case" MACT – under the CAA.[42] Because sources regulated under these four proposed rules would also be covered by EPA's proposed activation of the case-by-case MACT requirements, these parties have had to shift their attention and efforts to consider potential implications of EPA's §112(j) proposal. EPA has asserted that case-by-case MACT standard setting will not interfere with the ongoing Boiler MACT rulemakings. However, sources have no binding assurance that EPA will not impose multiple simultaneous regulatory demands related to Boiler MACT standards. The undersigned entities urge EPA to consider the pernicious impact that an ill-timed final § 112(j) rule would have on both regulated sources and the States. In addition to extending the comment period for these rules, EPA should also adopt deadlines in these rules and in any final § 112(j) rule that will not impose duplicative obligations on sources to participate in case-by-case MACT and federal Boiler MACT proceedings.

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[41] *See, e.g.,Sierra Club v. Jackson*, No. 01-537 (D.C. Cir.)(Nov. 10, 2008 Order extending deadlines for EPA to promulgate area source standards); (Sept. 8, 2009 Order extending deadlines for EPA to promulgate area source standards and extending deadlines for Boiler and CISWI MACT standards); (May 7, 2009 Order extending deadlines for EPA to promulgate area source standards); (Sept. 8, 2009 Order extending deadlines for area source standards and boiler and CISWI MACT standards).

[42] *See* 75 Fed. Reg. 15655 (Mar. 30, 2010).

VI. Conclusion

For all of the reasons discussed above, EPA should extend the public comment on these four proposed rules by an additional 90 days. EPA should take the necessary steps in *Sierra Club v. EPA* to make that adjustment as well as a corresponding adjustment of at least 90 days to the deadline for issuing a final rule. EPA should not shortchange its own process of reviewing and substantively responding to comments. Given the tens of billions of dollars of compliance costs that these rules will impose on the industrial, commercial and institutional sectors nationwide, EPA should ensure that it has respected all statutory and constitutional procedural requirements in its administrative process. In addition, EPA should ensure that any rulemaking procedures regarding the 112(j) case-by-case MACT process are similarly delayed so that affected sources and regulatory authorities do not need to spend unnecessary time and effort addressing case-by-case MACT when final MACT/CISWI/Solid Waste Definition rules are pending.

Thank you for your consideration. If you have any questions, you may contact me at 703.250.9042.

Sincerely yours,

Robert D. Bessette
President, Council of Industrial Boiler Owners
on behalf of all entities identified above

Attachment A

cc: Gina McCarthy, EPA Assistant Administrator for Office of Air & Radiation
Mathy Stanislaus, EPA Assistant Administrator for Office of Solid Waste & Emergency Response
Scott Fulton, EPA General Counsel

ATTACHMENT A

June 23, 2010 Request for Extension of Comment Period

Description of the Development of the Boiler MACT Database

The proposed emission limits for the Boiler MACT and related rulemakings are based on emission test results contained in the Microsoft Access database "Emissions Database for Boilers and Process Heaters Containing Stack Test, CEM, & Fuel Analysis Data Reported under Information Collection Request (ICR) No. 2286.01 and ICR No. 2286.03 (version 5)". Under the first Information Collection Request (ICR), companies with boilers and process heaters were asked to submit summaries of available emission test and fuel analysis results using spreadsheets. A database was created from the spreadsheet submissions and it was used to assess the need for additional data to support the Boiler MACT rulemaking.

The second ICR mandated extensive stack testing and fuel analyses at roughly 150 boilers. EPA selected these boilers to fill perceived information gaps in the database and to obtain additional test data from numerous 'best performing' units to examine emissions variability. A set of instructions accompanied the second ICR covering:

- sampling methods to be used
- minimum sampling volumes for different pollutants
- how non-detect values should be handled and reported
- how boiler heat input rates should be calculated
- data reporting and submission procedures

The initial set of instructions contained a number of unclear or ambiguous requirements, which necessitated six subsequent question and answer (Q&A) and guidance documents and an EPA webinar to clarify what EPA really wanted. Because EPA set a four-month time frame for the tests to be performed and results to be submitted to EPA, many companies had already contracted with stack sampling firms and had an agreed-upon scope of work before EPA had made final clarifications to the instructions.

The emissions database with the combined results from the first and second ICRs was first released in January 2010 and then revised in February 2010, March 2010, and April 2010 (Version 5). Revisions were made to incorporate late-arriving results from the second ICR, delete information from units that had ceased operation, correct data that had been entered into the database from faulty output from EPA's Electronic Reporting Tool (ERT), adjust dioxin/furan test results, and correct miscellaneous reporting inconsistencies and other problems.

The file size for Version 5 of the database is about 110 MB. It contains 44,389 records with emission test results; 92,822 records with fuel analysis information; and 44,219 records with continuous emissions monitoring systems (CEMS) data. This is a massive amount of information and it is unrealistic to expect that every value in the database has been checked by EPA and its contractor for accuracy. However, only a small fraction of the emission test results in the database has actually been used for developing the proposed numerical standards and it is realistic to expect this information has been thoroughly reviewed and cross-checked. A limited examination of stack test reports and associated laboratory analysis reports from a limited range of source subcategories demonstrates that EPA has so far failed to do an adequate review of the test results being used to develop the proposed emission limits.

FRED UPTON, MICHIGAN
CHAIRMAN

HENRY A. WAXMAN, CALIFORNIA
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May 20, 2011

Mr. John Walke
Senior Attorney and Clean Air Director
Natural Resources Defense Council
1200 New York Avenue, N.W., Suite 400
Washington, D.C. 20005

Dear Mr. Walke:

Thank you for appearing before the Subcommittee on Energy and Power on Friday, April 15, 2011, to testify at the hearing entitled "The American Energy Initiative."

Pursuant to the Rules of the Committee on Energy and Commerce, the hearing record remains open for 10 business days to permit Members to submit additional questions to witnesses, which are attached. The format of your responses to these questions should be as follows: (1) the name of the Member whose question you are addressing, (2) the complete text of the question you are addressing in bold, and then (3) your answer to that question in plain text.

To facilitate the printing of the hearing record, please respond to these questions by the close of business on Friday, June 3, 2011. Your responses should be e-mailed to the Legislative Clerk, in Word or PDF format, at Allison.Busbee@mail.house.gov.

Thank you again for your time and effort preparing and delivering testimony before the Subcommittee.

Sincerely,

Ed Whitfield

Ed Whitfield
Chairman
Subcommittee on Energy and Power

cc: Bobby L. Rush, Ranking Member, Subcommittee on Energy and Power

Attachment

Subcommittee on Energy and Power
The American Energy Initiative
April 15, 2011
Additional Questions for the Record

The Honorable Charles A. Gonzalez

1. Should there be a neutral third party designated to review the science and cost estimates put forth by both EPA and industry stakeholders with regard to proposed rulemakings ? If so, who should that third party be and why?

The Honorable Charles A. Gonzalez

Q. Should there be a neutral third party designated to review the science and cost estimates put forth by both EPA and industry stakeholders with regard to proposed rulemakings? If so, who should that third party be and why?

I do not believe such a routine third-party review is necessary or advisable. EPA has the necessary scientific and economic expertise to conduct scientific analysis and cost estimates to comport with governing laws and executive orders. The agency's analysis is carried out transparently, pursuant to notice and comment procedures, with members of the public accorded the opportunity to understand, critique, supplement or ratify that analysis.

The additional resources in the form of third-party reviews needed to review and critique EPA and industry scientific analysis and cost estimates for every agency rulemaking would be vast and duplicative. There would need to be either a new bureaucracy created or substantial taxpayer dollars given to third parties to serve as reviewers.

More troubling are the unavoidable delays that would result to EPA rulemakings, many of which already are proposed long past mandatory statutory deadlines. Such delays already impose significant harms to public health and safety, and further delays are not welcome. For example, due to delays and unlawful rules by the prior administration, life-saving clean air rules are now overdue by nearly a decade and the consequences have been tens of thousands of preventable premature deaths.

There are precedents for Congress asking neutral third parties to review elements of agency rulemakings, and this option remains an available course to conduct third party reviews as needed on a case-by-case basis. Experience confirms that problems warranting such review are isolated rather than systematic, making a more tailored, case-by-case review approach appropriate. In such circumstances, the National Academy of Sciences is often asked to review the science. Also, the highly regarded Health Effects Institute was set up for just this purpose for scientific questions related to clean air. (The Academy should absolutely not be put in the position of having to serve as a routine third-party reviewer, given its time-consuming processes and the need to preserve its prestige and political capital for matters where it can play a unique role.)

Finally, I question the wisdom of creating a government-sponsored arbiter of competing and conflicting scientific and economic claims between EPA and members of the public. Courts sometimes play this role pursuant to very specific laws and jurisdictional grants from Congress, in furtherance of upholding the laws of the United States.

It is a very different matter, however, to create or authorize a government-sponsored entity whose standing responsibilities are to judge the "truth" of contested scientific and economic claims. That challenge is better served in the marketplace of ideas by a multitude of diverse voices among the public.

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Dirk J. Krouskop
Vice President
Safety, Health & Environment

June 3, 2011

Legislative Clerk
Committee on Energy and Commerce
2125 Rayburn House Office Building
Washington, DC 20515-6115

Dear Ms. Busbee:

This is in response to the question posed by the Honorable Charles A. Gonzalez in follow-up to the testimony provided to the Subcommittee on Energy and Power at a hearing on April 15, 2011 entitled the "American Energy Initiative".

The question is as follows:

> **Should there be a neutral third party designated to review the science and cost estimates put forth by EPA and industry stakeholders with regard to proposed rulemakings? If so, who should that third party be and why?**

Response:

> Independent third party review would be beneficial to the regulatory process and the analyses that are used to support policy decisions. Estimates of costs and benefits should be developed in a transparent process, with assumptions clearly outlined and defendable based on the best economic methods and peer review of the underlying science. The Office of Management and Budget (OMB) plays a central role in overseeing the quality of regulatory impact analyses (RIAs) which include cost estimates and science assessments through Circular A-4 and guidelines for conducting cost-benefit analyses. Other Federal Departments have expertise to look at aspects of economic impacts, such as effects of regulations on balance of trade (imports and exports), energy, natural resources or international competitiveness. All of these approaches suffer from an inadequate analysis of market based capital allocation decisions and fail to provide adequate consideration for destruction of human capital from these decisions. Third party review would be one way to make sure more transparency exists in these estimates. Additionally, OMB should also exercise stronger oversight in ensuring that agencies adhere to existing OMB RIA guidelines especially for rules that are economically significant due to either their costs or benefits.

Please contact me by e-mail at dirk.krouskop@mwv.com or by telephone at 804-444-7040 if there are further questions.

Sincerely,

Dirk J. Krouskop
Vice-President Safety, Health and Environment

Subcommittee on Energy and Power
The American Energy Initiative
April 15, 2011
Additional Questions for the Record

The Hon. Charles Gonzalez

1. Should there be a neutral third party designated to review the science and cost estimates put forth by both EPA and industry stakeholders with regard to proposed rulemakings? If so, who should that third party be and why?

Aris Papadopoulos, Chairman of the Board, Portland Cement Association

Answer: EPA often includes estimated cost impacts as part of the Regulatory Impact Analysis (RIA) attached to proposed rulemakings. Because the EPA estimates are consistently lower than those submitted by industry stakeholders, and the lack of clarity concerning agency inputs and methodology with respect to those estimates, PCA recommends that federal officials consider solicitation of feedback from third parties. Submission of cost estimates from the General Accounting Office and the American Enterprise Institute, for example, could result in a more balanced and transparent rulemaking process.